

# Restructuring Connecticut's Renewable Portfolio Standard

FINAL

PREPARED BY

The Connecticut Department of Energy  
and Environmental Protection



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## EXECUTIVE SUMMARY

Connecticut can improve the alignment of its existing Renewable Portfolio Standard (RPS) with the Governor's goal of providing cheaper, cleaner, and more reliable electricity for the state's citizens and businesses. Connecticut's RPS was established in 1998 to provide a financial incentive for developers to bring renewable power projects into the marketplace, by requiring electricity providers to purchase an increasing percentage of the power they supply from renewable sources.<sup>1</sup> The RPS was designed to achieve several objectives: reduce dependence on fossil fuels, create a hedge against volatile oil and natural gas prices, lower air emissions, promote clean energy jobs, and drive economic development.

This study, prepared by the Department of Energy and Environmental Protection (DEEP) in accordance with Section 129 of Public Act 11-80, concludes that the objectives that motivated enactment of the RPS in 1998 remain valid, the RPS framework needs to be updated in order to meet those objectives more effectively, and at a lower cost to Connecticut ratepayers. Under the current RPS structure, Connecticut ratepayers' investments in clean energy are going largely to older, out-of-state and not-very-clean biomass and landfill gas facilities.

- In 2010, in-state renewable projects accounted for only 11% of Connecticut's Class I RPS standard. This means that 89% of the ratepayer investment in supporting renewable generation through the RPS was spent outside of the state, meaning that Connecticut does not enjoy the economic benefits associated with in-state projects.
- In 2010, a total of 76% of Connecticut ratepayer's investment in Class I resources went to support biomass plants located primarily in Maine and New Hampshire. These plants are among the least "clean" Class I resources. Another 13% of Connecticut's Class I requirement was supplied by landfill gas projects located primarily out-of-state. The clean energy produced by a few of these projects is already counted towards New York's renewable goals, thus the output from these resources is being double counted.

Connecticut's present RPS framework also leaves ratepayers exposed to potential electricity price increases from an inadequate supply of renewable power to meet the state's RPS targets,

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<sup>1</sup> Owners of electricity generation projects that qualify as renewable under one of the three classes of Connecticut's RPS receive one renewable energy credit (REC) for every megawatt-hour (MWh) of electricity they produce. These RECs have a dollar value attached to them as power suppliers must reconcile each year the electricity they supply to the marketplace with the RECs they have purchased.

causing electricity providers to pay so-called “alternative compliance” payments, which in turn can saddle homeowners and businesses with higher electricity costs.

This study calls for a revised RPS framework that can better meet the objectives of the RPS and the state's Global Warming Solutions Act, by maximizing the benefits from a more diverse power supply, improving our electric system's reliability, advancing greenhouse gas and air pollution emission reductions while minimizing the costs for electric ratepayers, and continuing to support local renewable projects that bring jobs and revenue to Connecticut's economy. Specifically, this study proposes:

- **Continue the state's existing commitment to clean energy incentive programs to maximize deployment of cost-effective in-state renewable power.** As of 2011, Connecticut produced only about 5% (66 MW) of New England's renewable capacity, while accounting for more than a third of the Class I RPS demand in the region. As a result of renewable energy programs launched by the Malloy Administration under Public Act 11-80—including residential solar incentive programs administered by Connecticut's innovative “Green Bank” and the Low Emissions and Zero Emissions Renewable Energy Credit (LREC/ZREC) programs—Connecticut has increased its deployment of in-state Class I resources ten-fold since 2010, and is on track to deploy 55 MW of new Class I-eligible electricity in 2013. By 2020, it is estimated that 5% of the state's total electricity demand (and 25% of the state's Class I target) will be supplied by in-state renewables. An additional measure that could help to mitigate the impact of RPS compliance costs on customers' bills would be to utilize any alternative compliance payments as a refund to electric customers to offset the costs of in-state renewable programs such as LREC/ZREC.
- **Support a gradual transition away from subsidies for biomass plants and landfill gas facilities that do not provide optimal economic or environmental benefits.** This study recommends a gradual phase-down of the disproportionate share of Connecticut's RPS that is met by biomass and landfill gas facilities, many of which have been in existence since before the State's RPS was established. By gradually reducing the value of renewable energy credits awarded to those sources, the State can replace many of these resources with new, cleaner resources such as wind power, solar arrays, or other zero-emissions renewables. The study also recommends that the State be authorized to enter into power purchase agreements with some of these facilities if it determines that retaining them provides economic benefits to the state, is in the interest

of ratepayers and furthers the goals of the Comprehensive Energy Strategy and the Global Warming Solutions Act (ie., because the withdrawal of RPS support for a biomass or landfill gas facility would otherwise cause it to exit the market, and be replaced by fossil fuel generation).

- **Expand support for small hydropower.** Under current RPS rules, to qualify for Class I, a hydropower project must be built after 2003, be run-of-river, and have a generating capacity of less than 5 MW. This study recommends expanding the definition for Class I hydro eligibility from 5 MW to 30 MW to broaden support for hydropower and better align rules with neighboring states, at the same time to ensure proper environmental safeguards are in place the definitions should clarify that an eligible small hydropower facility must not be based on a new dam or a dam identified as a candidate for removal, and must meet state and federal requirements and any applicable site-specific standards for water quality and fish passage.
- **Expand support for anaerobic digesters and biologically-derived methane.** Connecticut currently allows “methane from landfill gas” as a Class I resource, as do each of the other New England states. This study recommends that the Class I definition be modified to allow all methane/biogas that is biologically-derived—i.e., produced from sources such as yard and plant matter, food waste, animal waste and sewage sludge—and produced by new technologies such as anaerobic digesters to qualify as a Class I source.
- **Authorize the state to procure low-cost Class I renewable supply through long-term contracts.** This study recommends that DEEP should be given authority to participate in regional renewable procurement for Class I resources. This study proposes several rounds of clean energy procurement in the next year or two. The resources would ideally be procured in conjunction with other New England states and would be used to help meet the existing Class I requirements.
- **Authorize the State to contract for low-cost, low-carbon, large-scale hydropower to complement in-state and regional renewable energy procurements, provide greater diversity in energy supply, and help achieve the requirements of Connecticut's Global Warming Solutions Act.** Large-scale hydropower resources, such as those found in Quebec and the Eastern Canadian provinces, offer a source of low-carbon power at very competitive costs that has the

potential to increase the diversity and reliability of electricity generation in a state that is dominated by nuclear and natural gas generation, and to provide a cleaner alternative to natural gas that can “balance” intermittent resources like solar and wind. This study recommends authorizing the State—either on its own, or in coordination with other New England states—to solicit proposals for long-term contracts for Class I resources or large scale hydropower for up to five percent of the state’s load. Under the proposal in the final version of this study, any contracted large-scale hydro would not automatically count toward meeting the RPS compliance obligation, but would be counted toward the greenhouse gas reduction requirements of the state’s Global Warming Solutions Act. In the event that there is a verified shortfall in Class I supply, this study proposes a mechanism whereby large-scale hydro could be allowed to count towards up to one-percent of the RPS target, and no more than five percent by 2020, without receiving any RECs. Such a mechanism could help to reduce RPS compliance costs for Connecticut ratepayers. This proposal will preserve the opportunity for Class I projects to meet the current RPS standards, while at the same time creating a hedge to protect ratepayers from high RPS compliance costs if eligible Class I projects cannot be developed in time.

- **Discontinue Class III incentives for efficiency programs that are already ratepayer funded.** There is a significant oversupply of Class III resources. Since the programs provided through the State’s Conservation and Load Management Plan are already supported by ratepayers, this study recommends that any efficiency programs supported by ratepayer funding through the Energy Efficiency Fund not be eligible to qualify for additional ratepayer support through the Class III market. Eliminating these resources would open up the market to more combined heat and power (CHP) projects and third party efficiency providers not supported by the Conservation and Load Management programs.

The recommendations described above will enable Connecticut to achieve a more balanced and flexible approach to renewable power development, continue support for in-state renewable power projects that benefit the local economy while working with neighboring states to procure the cheapest possible regional renewable resources in the near term, and maintaining the flexibility to purchase large amounts of low-cost, large-scale hydropower and apply them towards the RPS in the event that cost-competitive regional Class I resources are in short supply. By taking structured steps to procure renewable electricity, Connecticut can also help to drive smart clean energy investments that will reduce greenhouse gas emissions, improve the

flexibility and reliability of the electricity grid, achieve rate suppression in Southern New England, and provide a hedge against spikes in natural gas prices. These steps will also help to increase the diversity of Connecticut's electricity supply, and potentially secure greater supplies of clean, low-cost power during times of peak demand. Such a new RPS structure would reinforce the policy direction of Connecticut's new Comprehensive Energy Strategy, and advance Governor Malloy's commitment to cheaper, cleaner, and more reliable electricity.

## **SUMMARY OF COMMENTS AND CHANGES TO DRAFT STUDY**

To assist with the development of this study, DEEP retained an outside consultant, Sustainable Energy Advantage LLC, to prepare two white papers that provide additional technical analysis of (1) the issues and options associated with incorporating substantial low-cost, no premium renewable energy (large hydro-eligible) contracts into a Connecticut Class I RPS Sub-Tier ("Large Hydro White Paper" – Appendix I), and (2) the issues and options associated with potential adjustments to Connecticut Class I RPS eligibility ("Eligibility White Paper" – Appendix II). These documents are available on the DEEP website.<sup>2</sup>

DEEP released a draft of this study on March 18, 2013. Pursuant to a Notice of Request for Written Comments and Notice of Technical Meeting and Public Hearing dated March 18, 2013, DEEP invited written comments on the RPS Study draft during a thirty-day period ending April 19, 2013. DEEP conducted a technical meeting on April 4, 2013, to provide stakeholders an opportunity to present oral comments and pose questions to DEEP staff and its consultants on the draft RPS Study. DEEP also held a public hearing on April 11, 2013, to give stakeholders and the public further opportunity to provide oral comments on the draft study.<sup>3</sup> All written comments on the RPS study have been posted on the DEEP website.<sup>4</sup>

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<sup>2</sup>[http://www.dpuc.state.ct.us/DEEPEnergy.nsf/\\$EnergyView?OpenForm&Start=1&Count=30&Expand=10&Seq=6](http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=10&Seq=6)

<sup>3</sup> The recording of the April 4, 2013 technical meeting, and the recording of the April 11, 2013 public hearing are available on the DEEP website at [http://www.dpuc.state.ct.us/DEEPEnergy.nsf/\\$EnergyView?OpenForm&Start=1&Count=30&Expand=10&Seq=11](http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=10&Seq=11). A transcript of the technical meeting will be posted on the same webpage as soon as it becomes available.

<sup>4</sup> All written comments on the Draft RPS study are also available on the DEEP website at [http://www.dpuc.state.ct.us/DEEPEnergy.nsf/\\$EnergyView?OpenForm&Start=1&Count=30&Expand=10.3&Seq=2](http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=10.3&Seq=2).

Most of the written comments focused on a few key issues: (1) the inclusion of large-scale hydropower from Canada, (2) proposed alteration of the biomass qualification, (3) authority to procure large-scale hydro and/or existing Class I renewables, and (4) impact on in-state renewable generation. A summary of these comments is provided below, and a matrix of all of the comments submitted is attached to this study as Appendix A.<sup>5</sup>

## Summary of Comments on Key Topics

### Inclusion of Large-Scale Hydropower

DEEP received many comments regarding the inclusion of large-scale hydropower in the RPS, expressing concern that this inclusion would undermine RPS support for local generation of renewable energy. Many commenters would prefer, under RPS stated objectives, to support and strengthen the local economy and create jobs in Connecticut, rather than send ratepayer money out of the country. Furthermore, several commenters note that the RPS is not intended to support mature technology like large-scale hydropower.

Many commenters also emphasized the environmental and social impacts resulting from the construction and use of large-scale hydropower facilities. According to these commenters, these environmental problems include, but are not limited to, flooding of forested land causing habitat destruction and greenhouse gas emissions, diverting rivers, and raising mercury levels in surface waters. Social impacts associated with large-scale hydropower development involve First Nations communities who depend on land for food, fiber, and cultural well-being and that would be negatively impacted by the widespread flooding and habitat alterations resulting from large hydropower projects. Many commenters believe that Hydro Quebec, a Canadian hydropower company, has a mixed history with respect to the impacts of its operations on local First Nations communities. Most recently, conflict with the Innu over the company's Plan Nord is cited in some RPS comments. These commenters urged DEEP to consider the many negative externalities associated with large-scale hydropower development.

There are several reoccurring transmission issues raised in the comments on the Draft RPS study, namely: infrastructure cost and feasibility and energy security concerns. Inclusion of large-scale Canadian hydropower will require large-scale investments in transmission from

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<sup>5</sup> Note that in their comments on the DEEP RPS study draft, some commenters provided feedback regarding the proposed RPS amendments in Senate Bill 1138, which was under consideration by the Connecticut General Assembly during the public comment period on this study. DEEP considered those comments as relevant to this study.



Canada to Connecticut. Many are concerned that the high cost of such a project will be passed to ratepayers in Connecticut. Furthermore, the feasibility of such lengthy construction, especially through the White Mountains National Forest is questioned. If the required transmission lines are constructed, some have expressed concern about their reliability. The longer the transmission route, the more opportunity for problems to arise, from weather-related issues and solar flares that could jeopardize Connecticut's energy security.

Finally, several commenters recommend that DEEP remove the Low-Impact Hydropower Institute (LIHI) requirement for hydropower projects. These commenters doubt the efficacy and reputation of the current LIHI program, in addition to often overly costly requirements of LIHI certification. Commenters note that the state and federal oversight and requirements for the construction of hydropower facilities is quite stringent and should satisfy in place of LIHI qualification.

### **Proposals to Alter Biomass Qualification**

DEEP received many comments on (1) the proposal to change the inclusion of biomass as a Class I renewable; (2) the proposal to categorize older biomass plants as “legacy” facilities; and (3) the proposal for certain biomass facilities to purchase Regional Greenhouse Gas Initiative (RGGI) allowances or otherwise offset emissions from the trucks delivering biomass fuel to the plants. Several commenters expressed their support for elimination of biomass as a Class I renewable. They stated that biomass should be removed from consideration as an RPS energy source on the bases of: (1) deficient Energy Return on Invested Energy at scale; (2) poor fuel quality; (3) environmental impact; (4) higher lifecycle greenhouse gas (GHG) emissions; and (6) decreased energy security. DEEP also received comments opposing the elimination of biomass as a Class I resource. These commenters note that biomass is currently the largest source of Class I power. Additionally, there is significant uncertainty about when substitutes (hydroelectric imports from Canada or wind power from northern New England) for displacing or foreclosing biomass would be available. Finally, those in opposition to disqualifying biomass suggest that restricting or barring these facilities from Class I eligibility would create scarcity in Class I REC market, which would potentially increase alternative compliance payments (ACP) by ratepayers.

DEEP received comments against the Draft RPS proposal to categorize older biomass plants as “legacy” facilities. Commenters stated that from a public policy perspective, there is little gain in changing existing policy since technology around biomass combustion has not significantly changed since the early 1980s. Boiler technology would probably not be materially different

when replacing an “old” facility with a “new” one. Commenters expressed that historically, Connecticut has led in using RPS eligibility or biomass to drive technology, innovation and capital investment in the air pollution area. They stress that the state should not abandon this “technology forcing” approach in its RPS in favor of a bright line test based on a boiler’s age. Commenters note that this DEEP recommendation is a fundamental policy shift that will send a conflicting message to investors about the stability of Connecticut Class I market.

Furthermore, several commenters tied this proposal to the proposal to include large-scale Canadian hydropower and pointed out that when pitting “legacy” biomass generation against imported large hydropower, the environmental impacts created by large hydropower (e.g., major river diversions, massive flooding, resulting greenhouse gas (GHG) emissions, impact to wildlife, deforestation, stimulation of mercury mobilization) dwarf those created by biomass generation in New England. These commenters raise concern that some of the same questions the Draft RPS study poses for the impacts of biomass generation appear not to be asked of the impacts of large-scale Canadian hydropower.

Finally, DEEP received comments both in support of and in opposition to the proposal for certain biomass facilities to purchase RGGI allowances or otherwise offset vehicle emissions associated with the supply of fuel (mostly wood products) to biomass facilities. In support of the proposal, some commenters stated that the trucks used in the biomass process use diesel which is not carbon neutral, thus adding to the overall emissions from the biomass plants. In opposition, commenters urged DEEP to defer any decision on this proposal until the EPA completes its rulemaking on biogenic carbon emissions (draft rule is likely to be released this summer; a final rule is expected in 2014).

### **Procurement of Class I Renewables and Large-Scale Hydropower**

The comments on procurement of Class I renewables fall into two broad categories; those related to procurement of large-scale hydropower, and those related to procurement of all other sources. With respect to procurement of large-scale hydropower, DEEP received comments both in support and against such procurement. Comments in support of large hydro procurement state that with such procurement Connecticut will further its reputation for having one of the most progressive RPS strategies in the country. In addition, commenters note that procuring large-scale Canadian hydropower will save money for Connecticut ratepayers, by undercutting the ACP, and that increasing Connecticut’s RPS to include additional Class I hydropower will contribute to fuel diversity in the state.

The comments that DEEP received against procurement of large-scale hydropower are numerous. Commenters expressed concern that purchasing large-scale Canadian hydropower will increase the state's dependence on foreign energy sources; will displace growth of Connecticut's in-state Class I sources; will not contribute to job growth in the state; will depend on long transmission lines that are not yet constructed; will not be guaranteed to actually deliver hydropower-generated electricity, as there is no tracking in place in the Canadian hydropower market; and will not be a competitive procurement process, as there will be no other vendor besides Hydro Quebec that will respond to a solicitation.

With respect to procurement of existing Class I resources, DEEP also received numerous comments. Some stakeholders commented that procurement contracts will save money for Connecticut ratepayers, by avoiding the ACP. Other commenters suggested that the 150 MW cap in the draft RPS study is too low. Commenters expressed that the proposal favored wind power procurement, of which there is almost no in-state potential for development. Finally, DEEP received comments that long-term procurement contracts will result in over-priced electricity.

### **In-State Generation**

DEEP received many comments that were supportive of the general objectives of the RPS and the draft study, such as the need to reduce Connecticut's fossil fuel usage and increase affordable renewable energy. However, several commenters questioned the proposed methods and policies in the draft study. Comment included the need to increase in-state renewables, the need to include thermal technologies, and the importance of energy efficiency. Many commenters stressed the need to ensure that any changes to the RPS do not dilute the future growth of renewables in the state. Commenters express concern that the draft study recommendations will discourage renewable energy growth in the state and undermine the potential for green job development here in Connecticut. Furthermore, the geothermal industry in the state is concerned that the proposed change of the definition of "energy" to "electricity" would be detrimental to that industry. The geothermal industry requests that DEEP conduct an analysis to identify why geothermal should be excluded from Class I. Several commenters strongly asserted that geothermal energy can be a viable source of renewable power and would like to see its inclusion in the state's RPS. Finally, DEEP received comments regarding the importance of energy efficiency and noted that accurate modeling of energy efficiency investments is essential to the conclusions in the RPS study. As such, commenters would like to see more analysis on how energy efficiency progress can help Connecticut reach its RPS goals while offsetting the potential shortfalls of supply.

## New Analysis Included in Final Study

In response to comments received on the draft study, including some comments summarized above, DEEP undertook further analysis on certain issues, described briefly below and in greater detail in the body of this study. In addition, the data and assumptions underlying this further analysis are also provided in a separate Appendix B and are available on the DEEP website.<sup>6</sup> The issues analyzed include:

- **Reduced savings from a contracted tier of large hydropower procured at a 1 cent/kWh premium.** In the draft study, DEEP modeled the impact of large hydropower procurement on projected RPS compliance costs with an assumption that these resources would be procured at no premium to market. Some commenters expressed concern that the State would not likely be able to procure such resources without paying a premium. In response to these concerns, DEEP analyzed a new scenario that includes a premium of 1 cent/kWh for large-scale hydropower, to assess the potential impact on the anticipated savings (i.e., avoided RPS compliance costs) from procuring large-scale hydropower to fill a contracted “sub-tier” of the Class I requirement. In that scenario, described in detail in the final study, payment of a 1 cent/kWh premium for a contracted sub-tier in which 5% of the Class I requirements is filled with large-scale hydropower, the annual savings would shrink by about \$20 to \$30 million, from \$100 - \$129 million to \$81 - \$100 million in 2022. Note, however, that the final study no longer recommends procuring large-scale hydropower as part of a contracted sub-tier that would automatically count towards the RPS targets.
- **Compliance costs with lower load growth from expanded efficiency programs.** When modeling projected RPS compliance costs in the draft study, DEEP relied on the 2012 ISO-New England (ISO-NE) forecast for its assumption of expected load growth. The ISO-NE forecast does not factor in the roughly doubled level of investment in efficiency called for in the 2012 Integrated Resources Plan (IRP), which, as some commenters pointed out, would reduce load and consequently, reduce the RPS compliance obligation. In response to stakeholder requests, DEEP developed a sensitivity analysis that assumed increased energy efficiency targets consistent with the 2012 IRP (0.4% annual reduction to prior year's eligible load) beginning in July 2013. In

this sensitivity analysis, the annual compliance costs for Class I estimated for the reference cases are reduced by approximately \$20 million annually in 2022 due to greater efficiency.

- **Estimated Savings on RPS Compliance Costs Resulting from Class I Long-Term Contracts.** In response to stakeholder comments, DEEP conducted an additional sensitivity analysis to explore the potential impact on projected RPS compliance costs of procuring Class I renewables through long-term power purchase agreements (PPAs.). The sensitivity analysis examined (1) bundled PPAs, for energy, capacity, and RECs with regional wind projects in Maine, (2) PPA prices of \$75, \$85, and \$95/MWh (nominal levelized), (3) PPA duration of 15-20 years beginning in January 2016, and (4) PPA sizes of 150MW, 300MW, and 450MW (nameplate capacity). DEEP's analysis indicates that small savings could result from procuring Class I renewables through long term contacts when compared to the reference cases. This additional analysis underscores that the real benefit from the use of long-term PPAs as a hedge against the possibility of even higher compliance costs if Class I resources are not available and the shortage is even worse than anticipated. As a result, this new analysis supports the greater emphasis in the final study on the use of long-term power purchase agreements to help bring down the costs of RPS compliance.
- **Biomass Eligibility Scenario.** DEEP also considered the possible effects of implementing more stringent standards for operating resources (in particular, biomass emissions restrictions). There is substantial uncertainty as to the amount of supply that could comply with more stringent standards and as to whether plants could justify investments in emission control retrofits. The sensitivity (run on Scenario 3) assumes that only biomass resources will be affected, and considers futures in which 25%, 50% and 75% of the operating biomass fleet remain Class I eligible beyond 2015. Supply and demand are modeled to project REC prices and potential supply shortages under each outlook. The results were then evaluated through the compliance cost model to calculate annual and total compliance costs. The results indicate that savings would be reduced but would still persist if stricter biomass eligibility requirements were accompanied by a greater flexibility to use large hydro to fill a portion of the Class I RPS requirements.
- **Estimated cost of expanding Class I RPS requirements from 20% in 2020 to 25% in 2025 without the contracted Class I tier.** Based on interest from commenting parties, compliance costs were calculated in a scenario with a 25% RPS in

2025 with no contracted Class-I tier. The analysis was re-run to calculate the new cost of entry for 2021-2025 with increased demand, REC price forecast revised, and new REC prices run through a compliance cost model as a revised reference case with new demand targets and updated REC prices. The analysis estimates that annual compliance costs could increase by \$ 82 to 95 million by 2025 from increasing the Class I RPS requirements to 25% in 2025. Higher Class I RPS requirements could add \$ 238 to \$ 270 million to ratepayers electric bills over the five year period from 2020 through 2025.

## **Changes To Recommendations in the Final Study**

Based on the comments received, and the additional analysis summarized above, DEEP has modified the recommendations from those in the draft study. DEEP does not recommend that a separate contract tier, in which large hydro would qualify, be established at this time. Instead, DEEP recommends a more flexible approach in which large-scale hydro would only be used to meet a portion of the Class I RPS requirements if there is a shortage, and the shortage is expected to continue in the future. DEEP also modified its recommendation regarding biomass and landfill methane gas. This final report recommends that the phase down of biomass Class I eligibility be established in a separate proceeding. Finally, DEEP does not recommend any changes to the Class I RPS requirements after 2020 at this time. DEEP had recommended extending the requirements from 20% in 2020 to 25% in 2025 in the draft report.

## INTRODUCTION

This study offers a new approach to Connecticut's support for renewable electricity generation that will move the state toward Governor Malloy's model of a cheaper, cleaner, more reliable energy future. This approach will ensure that renewable resources supply an increasing share of Connecticut's electricity, maximizing the benefits of a more diverse power supply to increase reliability, reducing greenhouse gas and other air emissions, and supporting local renewable projects that bring jobs and revenue to Connecticut's economy—while at the same time minimizing the overall cost of renewables to Connecticut's electric ratepayers.

In 1998, Connecticut became one of the first states in the country to financially support the development of renewable energy by enacting a renewable portfolio standard (RPS).<sup>7</sup> At that time, electricity produced from renewable energy sources such as wind, solar, and small-scale hydropower was generally much more expensive than central power station electric generation fueled by oil, coal, and natural gas. The RPS model was adopted by states wishing to encourage the development of new renewable energy projects and — in states like Connecticut that undertook electricity market restructuring — to ensure that existing renewable energy generation would continue to operate in a competitive market.

Connecticut's RPS was designed to achieve several objectives: diversify the state's energy resource mix to promote reliability, provide a hedge against volatile fossil fuel prices, improve environmental conditions by reducing air emissions, create clean energy jobs, and enhance the quality of life in the state. The RPS has been amended several times since its enactment, to extend and increase Class I requirements, adjust the eligibility criteria for Class I and Class II renewable sources, and to add a new Class III to support combined heat and power (CHP) projects and energy efficiency.<sup>8</sup> At the time the RPS was enacted, it was not intended to address climate change. The enactment of the Global Warming Solutions Act in 2008, how, added new

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<sup>7</sup> Connecticut General Assembly H.B. 5005 "An Act Concerning Electric Restructuring", 1998.

<sup>8</sup> The Center for Energy, Economic, and Environmental Policy and the Rutgers Economic Advisory Service, "A Review of Connecticut's Renewable Portfolio Standards", Edward J. Bloustein School of Planning and Public Policy, Rutgers, the State University of New Jersey for the Connecticut Energy Advisory Board, July 18, 2011, retrieved from <http://www.ctenergy.org/pdf/CTRPSFORCOMMENT.pdf> at 8.



emissions reduction targets for the state that will be advanced in part through compliance with the RPS.<sup>9</sup>

Despite the many amendments to the RPS, there have been continued calls to review and refine Connecticut's RPS. In a 2011 report, the Connecticut Energy Advisory Board (CEAB) expressed concern that the policy objectives of the RPS needed to be more clearly defined and prioritized, and that more regular and formal analysis was needed to determine whether and how the RPS could better meet those objectives.<sup>10</sup> Public Act 11-80, enacted in 2011, answered the CEAB's call for further analysis of RPS by directing DEEP to conduct a comprehensive review of the RPS, which culminated in this study. The 2011 legislation specified that the review must evaluate: options for minimizing the cost to electric ratepayers of procuring renewable resources; the feasibility of increasing the RPS; as well as "the impacts, costs, and benefits of expanding the definition of Class I renewable sources to include . . . hydropower and other technologies that do not use nuclear or fossil fuels."<sup>11</sup>

Consistent with this statutory direction, DEEP assessed the current RPS structure to determine how effectively it supports the development of new renewable resources. The study then considered the potential impact of a variety of modifications to the RPS and other policies that might promote clean energy resource development. DEEP recognizes that a successful renewable portfolio standard must harmonize energy, environmental, and economic objectives. Certain policy options may minimize costs to Connecticut's ratepayers but at the same time limit the diversity of the state's energy portfolio. Other options may fulfill environmental goals while simultaneously hindering in-state economic development or dramatically increasing costs. The proposals and options offered herein are designed to drive down the cost of new renewable energy technologies and enable older renewable technologies to achieve cost-competitiveness, by harnessing market forces and competitive pressures to spur innovation and economies of scale.

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<sup>9</sup> See Connecticut General Statutes, Section 22a-200(a).

<sup>10</sup> *Id.*

<sup>11</sup> Section 129 of Connecticut General Assembly S.B. 1243 "An Act Concerning the Establishment of Energy and Environmental Protection and Planning for Connecticut's Energy Future", 2011.



## BACKGROUND

### Connecticut's RPS Structure in a Regional Context

A renewable portfolio standard is a policy mechanism that creates a financial incentive for developers to develop renewable energy projects, by requiring electricity providers to purchase set quantities of renewable energy thereby guaranteeing a market and steady stream of revenue for renewable generators. Under Connecticut's RPS, electricity providers who serve retail customers in Connecticut must obtain a certain percentage of the energy they sell to these customers from three categories, or "classes," of renewable energy generators, listed in Table 1.<sup>12</sup>

Owners of electricity generation projects that qualify as renewable under one of the three classes of Connecticut's RPS receive one renewable energy certificate (REC) for every megawatt-hour (MWh) of electricity they produce. These RECs are tradable commodities that allow the environmental attribute of the renewable energy to be bought and sold separately from the energy commodity itself. A renewable generator can either contract to sell its energy—"bundled" with the accompanying attribute value directly to an electricity provider (usually at a premium above the wholesale electricity price), or it can "unbundle" the REC and the energy and sell them separately in regional wholesale markets.

Under the current RPS, the percentage of electric load that must be met by Class I sources increases over time, from 10% in 2013, up to 20% in 2020. The Class II RPS requirement is 3% in 2012 and remains at that level through 2020 and the Class III RPS requirement, currently 4%, also remains constant through 2020. In the event that the supply of renewable energy in any of these classes is inadequate to meet the RPS requirements, electricity providers must comply with the RPS by making an Alternative Compliance Payment (ACP), which is set by statute at \$55/MWh. Any revenues collected from Alternative Compliance Payments are allocated to the Connecticut Clean Energy Finance and Investment Authority (CEFIA) to support the development of additional Class I resources.

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<sup>12</sup> In Connecticut, these electricity providers include the state's electricity distribution companies (EDCs), which purchase energy on behalf of standard service customers who continue to receive standard service, as well as retail electric suppliers that serve customers who have opted to purchase their electricity from a competitive supplier.

**Table 1: Connecticut RPS Classes and Eligibility Requirements**

Class	Target (2013-onward)	Eligible sources
<b>Class I</b>	10% in 2013; increases annually up to 20% in 2020	<ul style="list-style-type: none"> <li>• Solar</li> <li>• Wind</li> <li>• Fuel cell</li> <li>• Methane gas from landfills</li> <li>• Ocean thermal</li> <li>• Wave</li> <li>• Tidal</li> <li>• Run-of-river hydropower (&lt;5MW, began operation after July 1, 2003)</li> <li>• Sustainable biomass (NOx emission &lt;0.075lbs/MMBtu of heat input, &lt;500kW, began operation after July 1, 2003)</li> <li>• Low emission advanced renewable conversion technologies</li> </ul>
<b>Class II</b>	3%; does not increase	<ul style="list-style-type: none"> <li>• Biomass (NOx emission &lt;0.2 lbs/MMBtu of heat input, began operation before July 1, 1998)</li> <li>• Small run-of-river hydroelectric (&lt;5MW, began operation before July 1, 2003)</li> <li>• Trash-to-energy facilities</li> </ul>
<b>Class III</b>	4%; does not increase	<ul style="list-style-type: none"> <li>• Customer-sited combined heat and power (CHP) with operating efficiency &gt;50%, facilities installed after January 1, 2006</li> <li>• Waste heat recovery systems installed on or after April 1, 2007</li> <li>• Electricity savings from conservation and load management programs (begun on or after January 1, 2006)</li> </ul>

Source: Conn. Gen. Stat. §16-1(a) (26), (27), (44) & (45)

Connecticut's RPS policies must be viewed in a regional context. All of the New England states except Vermont have renewable portfolio standards. Under rules currently in effect in Connecticut and all other New England states, electricity providers can satisfy their RPS requirements with RECs purchased from renewable generation projects located in the ISO-New England control area (which includes Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut), or with RECs for energy imported into ISO-NE from an adjacent control area (i.e., Quebec, the Maritimes Control Area, or New York). Renewable generation within the ISO-New England control area is certified and tracked through a system called the NEPOOL Generation Information System (GIS).

While the geographic eligibility rules are the same across New England, each state's RPS has different eligibility criteria, percentage requirements, and ACP prices. For example, Connecticut's ACP is set statutorily at \$55 per megawatt-hour (MWh) for all classes. Maine, Massachusetts, and Rhode Island have higher ACP levels for Class I, which are adjusted

annually. Since the ACP is higher in those states, Connecticut may be the last to receive multi-state qualified RECs such as solar and wind when there are shortages. An actual shortfall would also occur in Connecticut a bit sooner than other states since Class I eligible projects would be more inclined to sell their RECs in states with a higher ACP. As a result of the differences in state eligibility requirements, a higher proportion of Connecticut's Class I RPS requirement will be filled with sources that only qualify in Connecticut, such as "legacy" (pre-1998) generation (primarily biomass and land fill gas) as well as fuel cells using natural gas.

These differences among state's RPS design have important consequences for the type—and price—of renewable generation that electricity providers will buy to comply with Connecticut's RPS. This, in turn, affects Connecticut's ability to achieve the policy objectives of its RPS, particularly within Class I. In the sections that follow, this study evaluates the types of resources that are currently supplying each class of Connecticut's RPS, and the current and projected costs of those resources, to determine how well, and how cost-effectively, the current RPS structure is providing cheaper, cleaner, and more reliable electricity. Before turning to the review of Connecticut's RPS classes, however, the study first provides an overview of renewable energy and energy efficiency programs established by the State to support in-state renewable energy projects. While separate from the RPS itself, these programs are having a significant impact on the amount of cost-effective in-state renewable generation that is or will become available to supply Connecticut's RPS requirements.

## **Connecticut Renewable Energy and Energy Efficiency Programs**

As of 2011, Connecticut had only about 5% (66 MW) of New England's installed renewable capacity, while it accounted for more than a third of the Class I RPS demand in the region.<sup>13</sup> In recent years, Connecticut has sought to remedy that imbalance by implementing programs to accelerate support of in-state renewable and energy efficiency projects, while also seeking to drive down costs. By using low-cost financing, targeted grant funding, and reverse auctions tied to long-term contracting, these programs are significantly increasing the amount of in-state capacity available to supply the state's RPS requirements. For example, 55 MW of renewable generation is set to come online in 2013 as a result of these new programs – a tenfold increase over previous years. Over the next ten years, these programs are expected to increase the

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<sup>13</sup> 2012 Integrated Resource Plan, Appendix D-8

percentage of the state's electricity demand supplied by in-state renewables from 1% to about 5-6% in 2022. These programs are described in more detail below.

Over the years, Connecticut has provided significant support for Class I and Class III resources. Connecticut's Project 150 program, launched in 2003 and later amended, required local electric distribution companies (EDCs) to enter into long-term contracts to purchase at least 150 MW of Class I renewables. Fourteen projects totaling 159.8 MWs were approved for participation in the program, but as of 2011 only four projects equaling approximately 47 MW appear to have been financed or are otherwise moving forward towards completion.<sup>14</sup> In addition to Project 150, Connecticut established a ratepayer funded grant and incentive program to promote the development of combined heat and power (CHP) projects, which qualify as Class III resources. This program resulted in the development of approximately 100MW of CHP between 2006 and 2009.

The passage of Public Act 11-80 in 2011 launched a series of new programs designed to dramatically increase the amount of in-state Class I renewable resources at increasingly lower costs, by using competitive procurements and leveraging ratepayer contributions. Public Act 11-80 established the nation's first "Green Bank", called the Connecticut Clean Energy Finance and Investment Authority (CEFIA), to promote investment in clean energy sources. CEFIA was also charged with developing a program to incentivize residential solar PV installations.<sup>15</sup> This program will support the deployment of at least 30 MW of new residential solar capacity by December 31, 2022. As of March 2013 (one year after the program launch), this program has already resulted in 8.2 MW of residential solar installations in development at an average price of \$4.65 per watt.<sup>16</sup>

Public Act 11-80 also established a Zero Emission (ZREC) and Low Emission (LREC) Renewable Energy Credit program.<sup>17</sup> Over six years beginning in 2012, the ZREC/LREC program requires the EDCs to enter into \$8 million worth of long-term (15 year) contracts annually for ZRECs (renewable energy credits from "zero-emission" Class I renewable energy resources such as

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<sup>14</sup> Docket No. 11-07-06

<sup>15</sup> Section 106 of Public Act 11-80.

<sup>16</sup> The rebates and performance-based incentives to support this program equate to a 15-year ZREC price of about \$110 per REC.

<sup>17</sup> Sections 107 and 110 of Public Act 11-80

solar, wind, and small hydro) and \$4 million worth of 15-year contracts annually for LRECs (renewable energy credits from “low-emission” Class I resources such as fuel cells, biomass, and landfill gas that meet certain emissions standards). The ZREC/LREC program utilizes a reverse auction structure, in which contracts are awarded on a competitive basis to the projects requiring the least subsidy. In its first year, the ZREC/LREC program resulted in contracts for more than 31 MW of renewable generation, with an average subsidy of 9 cents per kWh, well below the statutory price cap of 35 cents per kWh.<sup>18</sup>

Section 127 of Public Act 11-80 provided further support for Class I renewables by allowing private developers and the state's EDCs to submit proposals for up to an aggregate of 30 MW of new Class I renewable energy sources. DEEP conducted a competitive procurement and selected two 5 MW solar energy projects (East Lyme Solar Park and Somers Solar Center) for long-term power purchase agreements, representing one-third of the renewable generation procurement mandated by the Act. The EDCs are continuing to work on the development and approval of projects pursuant to their part of Section 127.

Finally, Public Act 11-80 established programs to support anaerobic digesters,<sup>19</sup> as well as small combined heat and power projects.<sup>20</sup> All of these in-state projects play a critical role in ensuring that the economic benefits associated with meeting the RPS accrue to the citizens of Connecticut. As noted above, under the current RPS framework, any alternative compliance payments made by an electric supplier or electric distribution company are currently allocated to CEFIA to support the development of additional Class I resources. However, DEEP proposes that such alternative compliance payments could be refunded to electric customers directly, to offset the costs of existing in-state renewable programs such as LREC/ZREC or Project 150. Flowing these alternative compliance payments back to customers would help to mitigate the impact of RPS compliance costs on customer bills.

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<sup>18</sup> See Connecticut Comprehensive Energy Strategy, p. 89, *available at* [www.ct.gov/energystategy](http://www.ct.gov/energystategy).

<sup>19</sup> Section 103 of Public Act 11-80 requires CEFIA to establish a three-year pilot program to support businesses using organic waste with on-site anaerobic digestion to generate electricity and heat. No more than five projects shall be approved, with a maximum size of one thousand five hundred kilowatts at a cost of four hundred fifty dollars per kilowatt. CEFIA is to allocate two million dollars annually from the Clean Energy Fund.

<sup>20</sup> As a result of the Public Act 11-80, DEEP was required to conduct a review of appropriate financial incentives to encourage installation of combined heat and power (CHP) – also known as “cogeneration” – systems of up to one megawatt of capacity. Following the review process, DEEP approved financial incentives of \$200 per kilowatt (kW). CHP projects are also eligible for grants of \$350 per kW from CEFIA. These programs are open to all developers of CHP systems, including municipalities.

## Costs of RPS Compliance

DEEP estimates that in 2012, Connecticut ratepayers invested approximately \$168.1 million to support RPS generation sources, with Class I resources accounting for about 90% of that total investment.<sup>21</sup> In August 2012, Class I RECs sold for approximately 5.2 cents/kWh, reflecting a recent upswing as a result of the supply going from surplus into shortage. Through 2012, the RPS targets have been met for all RPS classes and a surplus of Class II and Class III renewable resources continues to exist. This surplus has served to drive down Class II and Class III REC prices. In August 2012, the price of Class II was 0.4 cents/kWh, and Class III sold at the floor price of 1 cent/kWh. Under Connecticut's RPS, the Class II and Class III targets do not increase. Therefore, it is expected that the surplus supply will continue to keep Class II and III REC prices low and costs relatively constant through 2020. The historic cost estimates only include the cost of REC's, not other incentives or transmission costs incurred to develop these projects.

In the sections that follow, DEEP has made projections of the future cost of compliance with Class I, Class II, and Class III RECs. In its projections, DEEP included the total above-market cost for renewable energy including RECs, plus other Connecticut renewable program costs, and any incremental transmission costs projected to be supported by Connecticut electric ratepayers not factored into the projected cost of the REC. These historic compliance costs and future projections do not include other impacts that may result from the addition of renewable energy sources that benefit Connecticut ratepayers such as reducing the price of energy and capacity purchases, natural gas price suppression, or the economic benefits accruing to Connecticut from in-state renewable generation.

## CLASS I RESOURCES

RPS targets and eligibility criteria drive different policy goals within RPS classes. Some RPS classes function as “maintenance” tiers, with stable targets intended to maintain certain types of so-called “legacy” clean energy facilities that qualify as a “pre-RPS vintage”—meaning that the projects were already in existence when the RPS went into effect. These projects were made

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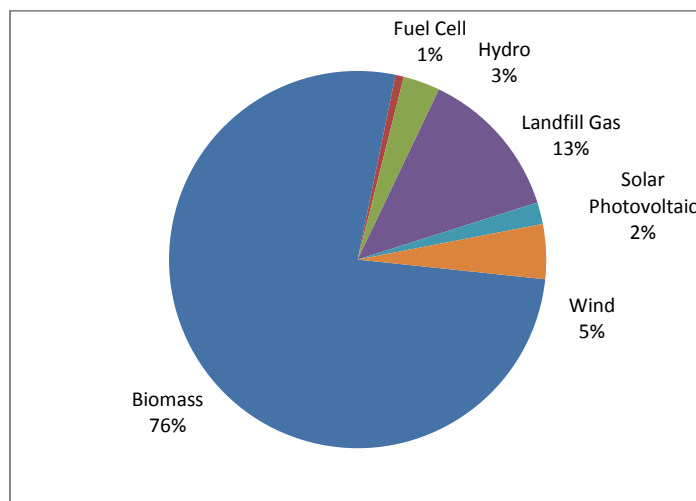
<sup>21</sup> These estimates of the RPS compliance costs to date are based on historic spot REC prices and only include the cost of RECs. DEEP did not attempt to estimate or include the cost of other subsidies or transmission costs that were incurred for existing resources that qualify for Connecticut's RPS. Nor did DEEP attempt to estimate the value of any hedging through longer-term contracts that may have occurred at lower prices than the spot REC price.

eligible for RECs when the RPS was first enacted in 1998, so as not to undermine support they had received in the pre-restructured energy market. By contrast, other RPS classes function as *growth* tiers, designed to spur investment in new renewable facilities by providing for increasing targets and narrower “vintage” eligibility requirements that restrict eligibility to facilities that were developed after the RPS went into effect. Because these new renewable facilities are “additional” to the electric system, they provide so-called “additionality” benefits by increasing the diversity of the fuel supply, displacing fossil fuel use, and reducing greenhouse gas and other emissions.

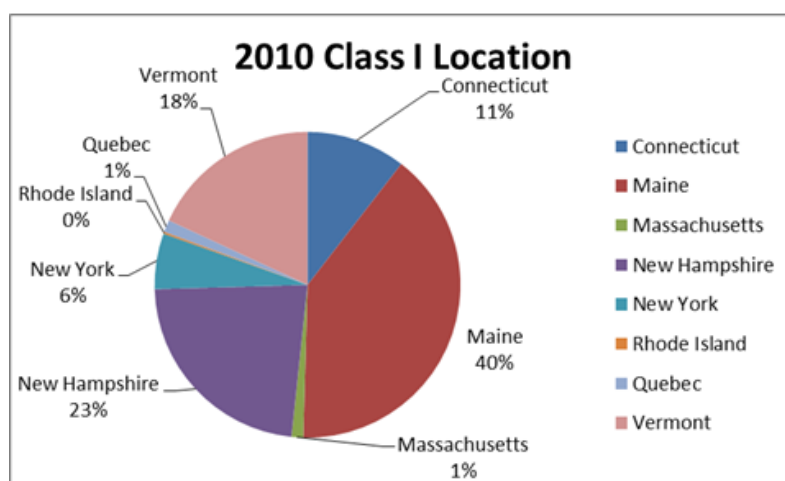
Connecticut's RPS classes have characteristics of both maintenance and growth tiers. Like growth tiers in other states, Connecticut's Class I tier currently has an increasing target, rising from 10% to 20% by 2020. Unlike growth tiers in other states, however, Connecticut's Class I allows pre-RPS vintage generation to continue to qualify regardless of whether their initial investment obligations have been met. This means that RECs from legacy facilities that do not qualify for growth tiers elsewhere in the region do count towards the Class I target in Connecticut.

As a result, in 2010, more than three-quarters of Connecticut's Class I target was supplied by wood and biomass facilities located in Maine and New Hampshire that are often not eligible as a Class I source in other New England states (Figure 1). Another 13% of Connecticut's Class I target in 2010 was supplied by landfill gas plants, located primarily in New York. Meanwhile, only 11% of Connecticut's Class I obligation was met by Connecticut based solar, fuel cells, or wind. As illustrated in Figure 2, below, most of the renewable power filling Connecticut's Class I target in 2010 was generated in facilities located in other states in the region. Fortunately, these new resources are growing rapidly. Solar and fuel cells represent the largest potential for growth in Connecticut based Class I resources. Wind has, by far, the largest potential in New England.

**Figure 1: Connecticut's Class I Resource Mix (2010)<sup>22</sup>**



**Figure 2: Location of Resources Filling Connecticut's Class I Requirement in 2010<sup>23</sup>**



## Projected Costs of Meeting Existing Class I Targets

The cost of meeting the Class I RPS has grown with the annual increase in the Class I target. The investment cost in Class I renewables was \$151.8 million in 2012. As the Class I RPS targets increase from 10% in 2013 to 20% in 2020, DEEP estimates that the annual cost of Class I compliance under the current rules could increase to approximately \$334 million to \$380 million in 2022 as a result of higher RPS targets and higher REC prices, potential future

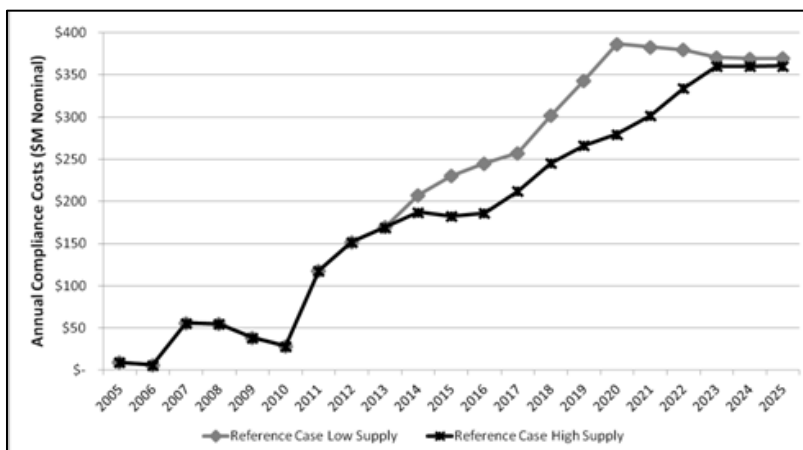
<sup>22</sup> DEEP RPS Database

<sup>23</sup> DEEP RPS Database



alternative compliance payments, and the cost of supporting in-state renewable energy programs.

**Figure 3: Connecticut's Annual Class I Compliance Cost – Historic and Reference Case <sup>24</sup>**

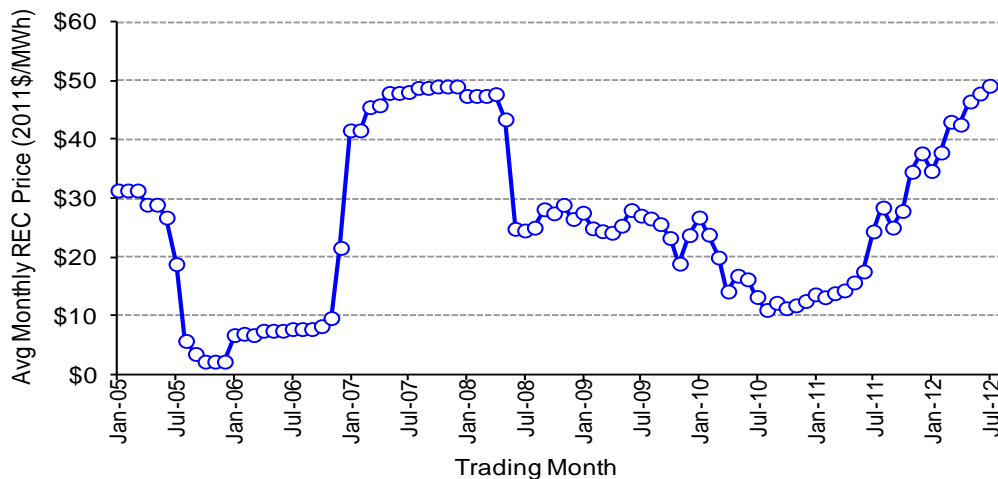


Compliance costs would decrease slightly if electric conservation spending is doubled to \$206 million as envisioned in the 2012 Integrated Resources Plan (IRP) and the 2013 Comprehensive Energy Strategy (CES) Increased conservation reduces overall load growth from .6% in the reference cases to -.4% thereby reducing the number of REC's needed to meet the RPS goal. In 2022 the estimated annual compliance cost is reduced by approximately \$20 million to \$318 million in the high reference case and \$360million in the low reference cases assuming higher conservation levels.

REC prices have fluctuated over the years due to market forces and legislative changes to resource eligibility. The supply of renewable power has grown each year to meet the increases in demand without sustained shortages or REC prices reaching the penalty level. More recently, however, the Class I market has swung from surplus into a modest near-term shortage. Class I REC prices have increased from less than 2.0 cents/kWh in July 2011 to nearly 5.0 cents/kWh by July 2012. This shortage is expected to last several years until new supply increments come online <sup>25</sup>

<sup>24</sup> Sustainable Energy Advantage, LLC (SEA) Analysis

<sup>20</sup> SEA Analysis

**Figure 4: Connecticut Class I REC Prices<sup>26</sup>**

Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices, for the current or nearest future compliance year traded in each month.

Escalating RPS targets are also mandated in each of the other New England states except Vermont (Table 2).<sup>27</sup> These higher RPS targets will raise the regional demand for Class I resources significantly over the next ten years. DEEP estimates that REC prices should decline from current levels during the 2015 timeframe, but will then rise because of increasing regional RPS requirements that will require additional supply not currently under development throughout the region. That need for new supply and the long timeframes required for projects in the development pipeline increase the risk of a shortage of Class I resources between 2019 and 2022. Under constrained conditions the price of Class I RECs could increase to levels approaching the Connecticut ACP level of 5.5 cents/kWh.

<sup>26</sup> SEA analysis, "Renewable Energy 101 Training" slide deck

<sup>27</sup> Vermont does not have a formal RPS; its Sustainably Priced Energy Enterprise Development program promotes renewables to meet all energy growth by 2012; for a detailed comparison of New England RPS Eligibility Requirements, see Appendix II Eligibility White Paper at p. 7.

**Table 2. Class I-Equivalent RPS Targets in New England as a Percentage of Load**<sup>28</sup>

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2025
CT Class I	9.0	10.0	11.0	12.5	14.0	15.5	17.0	19.0	20.0	20.0
ME Class I	5.0	6.0	7.0	8.0	9.0	10.0	10.0	10.0	10.0	12.5
MA Class I	7.0	8.0	9.0	10.0	11.0	12.0	13.0	14.0	15.0	20.0
NH Class I & II	3.2	4.2	5.3	6.3	7.3	8.3	9.3	9.9	10.8	15.3
RI	4.5	5.5	6.5	8.0	9.5	11.0	12.5	14.0	14.0	14.0

To inform this study, DEEP developed two “reference case” scenarios to estimate the future availability of Class I supply and its associated costs. One reference case modeled a “Low Supply” future, and the other modeled a “High Supply” future. Each reference case projects available supply considering the *lesser* of (1) what could be produced by the probability-de-rated renewable energy development pipeline, or (2) the current statutory availability of future long-term power purchase agreements (PPAs) in New England states. In each case, supply and demand are projected for the region and for each individual state, while considering state differences in eligibility. When the availability of projected supply falls short of demand, that gap must be met by either additional supply not in the current development pipeline, or (if such additional supply is insufficient) result in a risk of shortage and ACP costs. As would be expected, the Low Supply scenario results in an earlier onset of the need for additional supply, and higher cost of compliance, than the High Supply scenario.

Key assumptions common to both reference cases include: 363 MW from the Cape Wind development in Massachusetts, which is the amount currently under long term contracts; a common forecast of eligible supply imports into New England over existing transmission ties from adjacent control areas; no expansion of existing transmission ties in those adjacent control areas; no incremental New England States Committee on Electricity (NESCOE) regional coordinated procurement for long-term renewable energy contracts beyond what is envisioned under current statutes; and common eligibility and performance assumptions for the existing biomass fleet.

<sup>28</sup> 2012 Connecticut Integrated Resource Plan, Appendix D-6, Figure 4

The primary differences between the two reference cases are as follows. The Low Supply reference case assumes that:

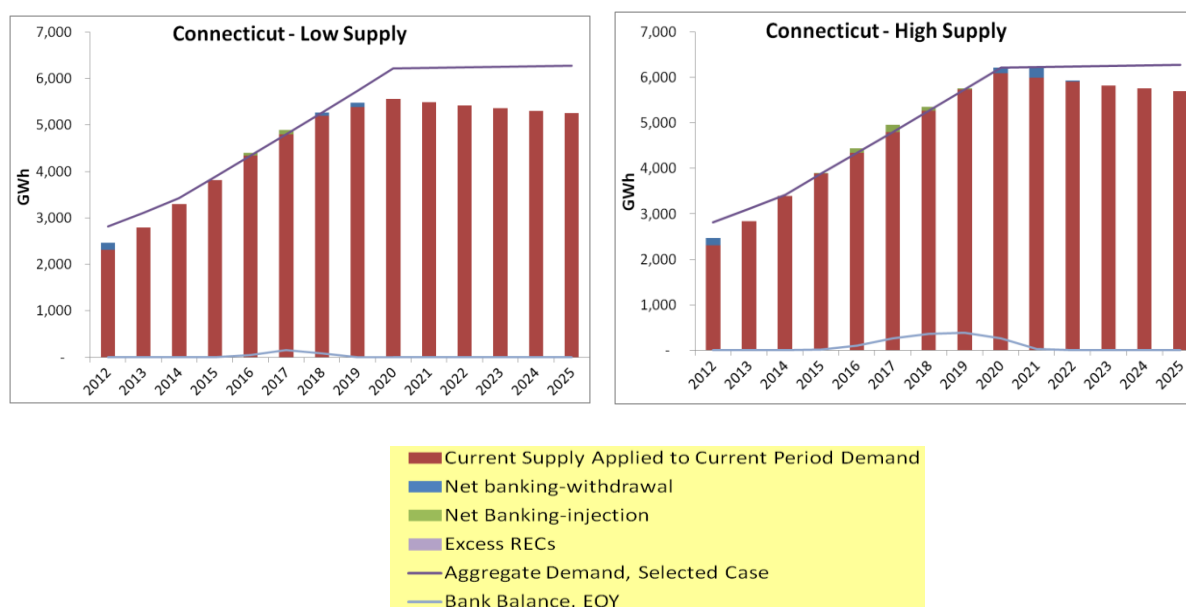
- Existing policies and programs continue unchanged
- Resources currently planned are built and no additional long-term contracts or new transmission upgrades in the region occur.
- Costs are impacted by an assumed extension of the Federal Production Tax Credit through 2014 followed by a phase-out by 2018.

As a result of these assumptions, the Low Supply scenario limits the amount of wind power that could be brought to market from remote locations in Maine, thereby contributing to the potential shortage of Class I resources estimated to occur in 2019. The High Supply scenario is more optimistic. In that scenario, DEEP assumes:

- New transmission is added, allowing more wind facilities to deliver their power to customers outside of Maine while securing capacity revenues.
- Rhode Island will add 450 MW of offshore wind in federal waters.
- The supply of landfill methane by pipeline available to meet the Connecticut Class I demand is assumed to be twice as large as that under the low supply future
- Other New England states will adopt additional policies intended to boost the success of their respective in-state RPS supplies.
- Costs of renewables are lower due to an assumed extension of the Federal Production Tax Credit through 2015, followed by a phase-down to 50% of its current value by 2020 (extended at that level indefinitely thereafter).
- State-sponsored renewable resources will receive an exemption in the forward capacity market (FCM) from the minimum offer price rule (MOPR), which is set for implementation in the 2017-2018 timeframe.<sup>29</sup>

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<sup>29</sup> Note, however, that on February 12, 2013, FERC concurrently issued an Order on ISO-NE's FCM compliance filing and an Order denying NESCOE's Section 206 Complaint in relation to a renewable exemption. The effect of these two Orders is that ISO-NE's implementation of buyer-side mitigation in the FCM (also known as the Minimum Offer Price Rule or MOPR) without an exemption for state-sponsored renewable resources will proceed for the 2017-2018 timeframe. Without such an exemption, new renewable resources are unlikely to receive revenues from the FCM, and New England ratepayers will not receive capacity credit for any new renewable resources through the FCM.

**Figure 5: Reference Case - Low Supply vs. High Supply**

The reference cases offer the following projections of Connecticut's renewable energy future. Over the next ten years, the share of Connecticut's Class I requirement provided by in-state renewable resources will increase as Project 150 facilities and projects developed in response to ZREC/LREC and other policies (detailed earlier in this study), begin operation. Generation from these programs will increase from a trivial quantity in 2012 to 4.6 % of the total eligible load in 2020. Importantly, as the Class I targets increase from 10% in 2013 to 20% in 2020, almost half (46%) of the increased target will be filled by these in-state resources, so that by 2020, almost a quarter (23%) of the overall Class I target will be by filled in-state resources.

While in-state facilities will help Connecticut meet its RPS requirements, the renewable resources most available in Connecticut—solar and fuel cells—can be relatively expensive compared to the least cost Class I renewable energy options available regionally. By 2020, in-state programs are expected to produce approximately 23% of the Class I RPS requirement, but are estimated to account for 32% to 45% of the total cost. However, these in-state projects bring local economic, environmental, and human health benefits to the state that do not accrue from out-of-state sources.

Under the reference cases, it is anticipated that much of the remaining regional Class I requirement will be met by wind resources located in northern New England or offshore. In order to meet Connecticut's growing RPS requirements and those of other New England states, it is likely that long-term contracts will be needed to finance the construction of generation

facilities and the accompanying transmission needed to move that power to load centers in Massachusetts and Connecticut. Additional in-state facilities could also be developed, but this would add additional costs to the reference case scenarios analyzed. If the cost of solar and fuel cells declines as expected over the next few years, this option may become more favorable as a way of meeting our RPS demand in the post-2020 timeframe.

The results of DEEP's analysis indicate that a potential shortage of Class I resources may not occur as early as estimated in the 2012 Integrated Resources Plan (IRP), issued by DEEP in June 2012. In the 2012 IRP, a shortage of Class I RECs was projected to occur in the 2017-2018 timeframe, compared to this study's analysis of that occurring in 2019 under the low supply scenario and 2022 under the high supply case. Although the IRP estimated the annual cost of the Base Case scenario in 2022 to be approximately \$445 million in 2012 dollars, the updated analysis in this study concludes that there could be a \$334 million to \$380 million price tag if other changes are not adopted. These changes are the result of new analysis in this study that incorporates the latest information on potential projects in the region, their cost and likelihood of success, and reductions to RPS targets in New Hampshire. The updated analysis also takes into account (1) the availability of new long-term contracting policies adopted since the IRP was issued, that support financing of regional projects, and (2) a detailed forecast of the ZREC and LREC programs and (3) methodological differences (e.g, banking of surplus, state-by-state differences) that address market dynamics that were not included in the IRP.

In response to stakeholder comments, DEEP conducted additional analysis to identify the impact of increased efficiency investments on the costs of RPS compliance. This additional analysis shows that if increased conservation reduces overall load growth from 0.6% in the reference cases to -0.4%, as called for in the 2012 Integrated Resources Plan, the annual cost of the RPS would decrease by about \$20 million, to between \$ 318 million and \$ 360 million in the high and low reference cases. While the estimated cost of Class I compliance under this study is lower than predicted by the 2012 IRP, these costs are still significant.

Although the costs of renewable energy, particularly solar and wind, have declined dramatically since enactment of Connecticut's RPS, they are still more expensive than anticipated when those out-year RPS targets were established. The Alternative Compliance Payment was set to provide a guarantee to financiers of renewable developers, achieving compliance through significant use of the ACP, however, was never the goal of the RPS.

Given the anticipated lag in renewable development, concerns about the resulting costs of meeting the RPS requirements within the current RPS structure have prompted analysis of other options that achieve the energy, environmental and economic development objectives of the RPS at a lower cost to Connecticut ratepayers. DEEP has examined two types of policy options that could be used to reduce the costs of complying with the current RPS and ensure that ratepayers' investments in the RPS are going to support the types of facilities that best achieve the RPS objectives. One option is to modify the eligibility criteria for Class I resources to expand the availability of Class I supply and maximize support for new facilities that use the cleanest, cutting edge technology and have the greatest potential to provide in-state economic benefits.

Another option is to allow procurements of low-carbon, large-scale hydroelectric power to help meet the requirements of the Global Warming Solutions Act and/or the RPS. DEEP has evaluated substantial changes that consider procurements of large scale hydropower that would allow a portion of Class I to be met by large hydroelectric power. There is significant potential for new large hydro development (greater than 30MW) outside of New England. Inclusion of these resources as part of Connecticut's portfolio offers many benefits, but requires special thought and consideration so as not to undermine other goals of the State's RPS. The analysis of these two options and resulting recommendations are presented in the sections below.

### **Options to Modify Existing Class I Eligibility**

DEEP has examined the current eligibility requirements for Class I resources and has compared them to other New England states with an eye to expanding eligibility where appropriate to increase the supply of Class I. Table 4a-c compares the qualifying technologies for each of the RPS Classes for the five New England states that have RPS requirements. All of the New England states qualify solar photovoltaic, ocean thermal, wave, tidal, and wind as Class I sources. Other technologies such as biomass, fuel cells, and hydro are also common, but the definition and qualifications for these technologies vary substantially from state to state. Connecticut is unique with its inclusion of fuel cells that utilize natural gas as a Class I resource, and cogeneration and energy efficiency as Class III sources. Connecticut is the only New England state to allow energy efficiency to qualify as a resource to meet any RPS requirements. Connecticut is also the only state to allow legacy supply, requiring no vintage threshold to limit Class I eligibility to new generation.

**Table 4a: Comparison of Regional Eligibility for Connecticut Class I-Eligible Resources**

Resource Type	CT Class	MA Class	RI Class	NH Class	ME Class
Solar	1	1	1	1	1
Wind	1	1	1	1	1
Fuel Cell - Natural Gas	1	Ineligible	Ineligible	Ineligible	Ineligible
Fuel Cell - Renewable Source	1	1	1	1	1
Landfill Methane Gas	1	1	1	1	1
Ocean Thermal	1	1	1	1	Ineligible
Wave	1	1	1	1	Ineligible
Tidal	1	1	1	1	1
Hydro	1	1	1	1	1
Biomass	1	1	1	1	1
Geothermal Electric	Ineligible	1	1	1	1
Anaerobic Digestion	Ineligible	1	1	1	Ineligible
Marine Hydrokinetic	Ineligible	1	Ineligible	Ineligible	Ineligible
Landfill Methane Gas by Pipeline <sup>30</sup>	1	1 <sup>31</sup>	Ineligible	Ineligible	Ineligible

**Table 4b: Comparison of Regional Eligibility for Connecticut Class II-Eligible Resources**

Resource Type	CT Class	MA Class	RI Class	NH Class	ME Class
Trash to Energy	2	2B	Ineligible	Ineligible	2
Biomass	2	2A	Ineligible	3	2
Hydro	2	2A	Ineligible	4	2

**Table 4c: Comparison of Regional Eligibility for Connecticut Class III-Eligible Resources**

Resource Type	CT Class	MA Class	RI Class	NH Class	ME Class
Combined Heat & Power	3	APS <sup>32</sup>	Ineligible	Ineligible	2
Waste Heat Recovery	3	Ineligible	Ineligible	Ineligible	Ineligible
Energy Efficiency	3	Ineligible	Ineligible	Ineligible	Ineligible
Demand Response	3	Ineligible	Ineligible	Ineligible	Ineligible

<sup>30</sup> This can be from a source outside New England, from specified locations when accompanied by an approved contract path for pipeline delivery.

<sup>31</sup> Proposed change under current rulemaking to add to eligible resources.

<sup>32</sup> CHP is included in MA's alternative energy portfolio standard or APS. CHP for class I is a subset of biomass eligibility (not explicit, but the de facto requirement of the high biomass conversion efficiency requirement)



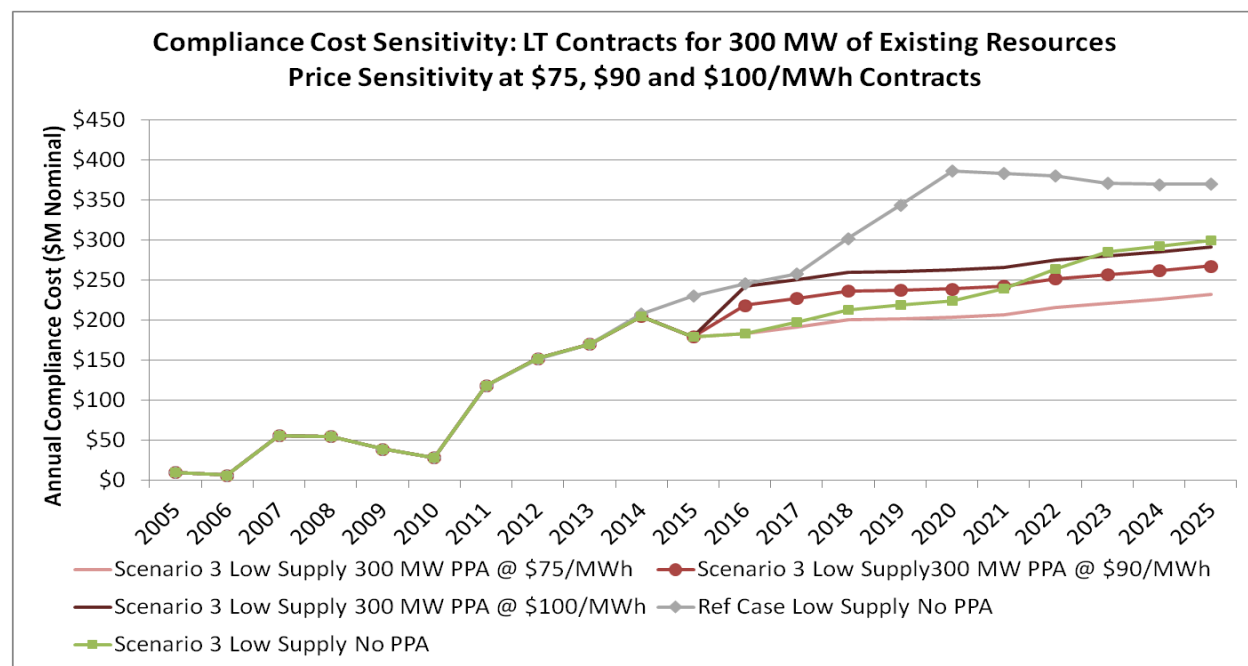
As a part of this study, DEEP requested that its consultant, Sustainable Energy Advantage, LLC (SEA) conduct a comprehensive analysis of Class I eligibility requirements. A detailed review of these eligibility considerations is presented in the whitepaper entitled “Eligibility Issues and Options Connecticut Class I RPS,” which is included in Appendix II.

### **Biomass and Landfill Gas**

Connecticut is the only state that allows legacy renewable facilities that were built prior to electric restructuring to qualify as Class I sources. As a result, Connecticut's Class I RPS has become a sink for these sources. Consequently, as compared to other states in the region, Connecticut ratepayers have been providing disproportionate support for keeping the region's legacy fleet running. Currently there are approximately 275 MW of biomass and 80 MW of landfill gas eligible in Connecticut—much of it located out-of-state. In 2010, Connecticut relied on biomass and landfill gas to meet 89% of its Class I REC requirements in 2010. These facilities are generally over 20 years old.

The concern related to subsidizing these legacy facilities is that ratepayer support might be better spent to finance the development of new cheaper, cleaner, renewable resources. Class I is currently short in supply, resulting in high REC prices in the near term. Sudden changes to the eligibility requirements could remove over 350 MW of capacity from Class I eligibility in the near term, and could cause REC prices to remain high for years, thereby increasing compliance costs. In addition, changes to biomass eligibility could have large impacts beyond just the RPS markets. Eliminating REC revenues for biomass and landfill gas projects might make these facilities uneconomic to operate. The potential immediate retirement of 350 MW in the absence of new renewable development to supply Connecticut's Class I requirement could adversely impact capacity markets, and potentially electric rates and reliability.

DEEP conducted additional analysis to evaluate the impact of imposing stricter eligibility requirements for biomass. In the analysis, DEEP assumed 25%, 50%, and 75% reductions in biomass capacity, in addition to assuming a contracted tier in which a portion of the Class I requirement could be filled with large scale hydro. The results of this analysis indicate that savings would be reduced significantly but would still persist if stricter biomass eligibility was accompanied with greater flexibility in enabling DEEP to procure large scale hydropower. Based on this analysis, DEEP believes that a careful, deliberate transition away from a reliance on legacy biomass facilities is appropriate if timed in a way that makes it possible for other Class I resources to be developed and large-scale hydro is allowed to meet a portion of the Class I requirements in the absence of adequate renewable supply in the market.

**Figure 7: Cost Sensitivity with Reductions in Biomass Eligibility**

### Geothermal and Solar Thermal

While geothermal and solar thermal qualify as Class I resources in several New England states, DEEP recommends that the electricity produced by geothermal steam generation be qualified as a Class I resource. The potential for this technology, however, is very limited in Connecticut. DEEP does not recommend that the definition of Class I be expanded to include geothermal heat pumps or solar thermal. DEEP believes that the RPS is intended to encourage the development of renewable electric generation or electric energy saving technologies. Geothermal heat pumps provide heat for space heating and may also provide air conditioning. Geothermal heat pumps already qualify as a Class III resource to the extent they save electricity. On the heating side, most of the savings resulting from the use of geothermal heat pumps are for gas and oil since only 10% to 15% of Connecticut residents heat their homes with electricity. Solar thermal is primarily used as an alternative for heating hot water and in some cases space heating and therefore is also a technology that primarily saves oil and gas. DEEP therefore does not recommend solar thermal be included as a Class I resource.

As part of the public process, some stakeholders submitted testimony in support of qualifying thermal electric conversion technologies as Class I resources. These technologies produce electricity from temperature differences in waste heat. These units, however, usually produce steam through the combustion of fossil fuels. DEEP believes that these resources are more consistent with CHP and efficiency technologies. The current definition of Class III allow waste

heat recovery systems installed on or after April 1, 2007, that produces electrical or thermal energy by capturing preexisting waste heat or pressure from industrial or commercial processes. DEEP believes that this technology already qualifies as a Class III resource and therefore no legislative changes are necessary at this time. If thermal conversion technologies use Class I resources to produce heat then it would be appropriate to include as a Class I resource.

### **Anaerobic Digesters**

Several states include anaerobic digesters as a Class I resource but it is not specifically mentioned in Connecticut's RPS legislation. DEEP recommends that anaerobic digesters be specifically qualified as a Class I source in Connecticut. Connecticut includes "methane from landfill gas" as a Class I resource, as do each of the other New England states. However, there is no definition of landfill gas in the Connecticut legislation. DEEP believes that methane should not be required to actually come from a landfill. PURA (the former Department of Public Utility Control) has interpreted the statute broadly, but it would be prudent to clarify that all biologically-derived methane/biogas from sources such as yard and plant matter, food waste, animal waste and sewage sludge is eligible as a Class I source.

### **Small Scale Hydroelectric Generation**

While the definition of eligible small-scale hydroelectric generation varies significantly among states, Connecticut's definition is the most stringent. Under Connecticut General Statutes Section 16-1 (a)(26), a hydro project must be run-of-river, built after 2003, and be less than 5 MW in order to qualify as Class I in Connecticut. Much larger projects can qualify in other states. In Massachusetts and Rhode Island, hydro projects up to 30 MW that are certified by the Low Impact Hydro Institute qualify as a Class I source; projects up to 100 MW qualify in Maine. DEEP recommends that the eligibility definition should be modified to allow post-2003 hydro projects up to 30 MW to qualify as a Class I source in Connecticut. Increasing the project size would be more consistent with other New England states and may expand the supply of Class I resources available to help Connecticut obtain its RPS requirement. DEEP does not believe that many completely new hydro facilities will be developed in New England in the future, but this modification could create an incentive for some existing sites in the 5 MW to 30 MW range to be refurbished or increase their output.

### **Options for Procurement of Low Carbon, Large Scale Hydropower**

As directed by Section 129 of Public Act 11-80, DEEP examined a variety of alternatives that could potentially reduce the overall cost of RPS compliance while simultaneously maintaining

the policy objectives advanced by Connecticut's RPS. For the draft version of this study, DEEP explored in detail a proposal to reduce the cost of meeting the Class I RPS targets while providing similar environmental benefits and advancing the state's clean energy goals, by allowing low carbon, large-scale hydropower resources to be eligible to meet a portion of the Class I RPS target as part of a contracted "sub-tier" that would not be eligible for REC payments. DEEP received many comments from stakeholders on this contracted sub-tier proposal. After considering those comments, DEEP has developed an alternative proposal for procuring low carbon large-scale hydropower resources, and allowing those resources to count toward the Class I RPS target only in the event of a shortage of supply of existing Class I-eligible renewables. This section recaps the initial contracted sub-tier proposal, summarizes the concerns raised in stakeholder comments on the contracted sub-tier, and then introduces DEEP's alternative proposal for procuring large-scale hydropower.

### **Initial Proposal: Contracted Sub-Tier**

DEEP investigated a full range of options for including large scale hydro to fill a portion of the Class I RPS requirements, taking into account the structure of the sub-tier; geographic location and vintage of eligible resources; the ability to deliver energy into the program's control area; potentially available supply and transmission capacity; environmental impacts; and contracting mechanisms. DEEP's analysis assumed that it may be possible to contract for Canadian hydro delivered into New England at approximately the projected market price of power while paying little or no renewable premium. The detailed results of this feasibility analysis are described in a white paper entitled, "Incorporating Substantial Low-Cost Renewable Energy (Large Hydro-Eligible) Contracts into a Connecticut Class I RPS Sub-Tier," (Appendix I).

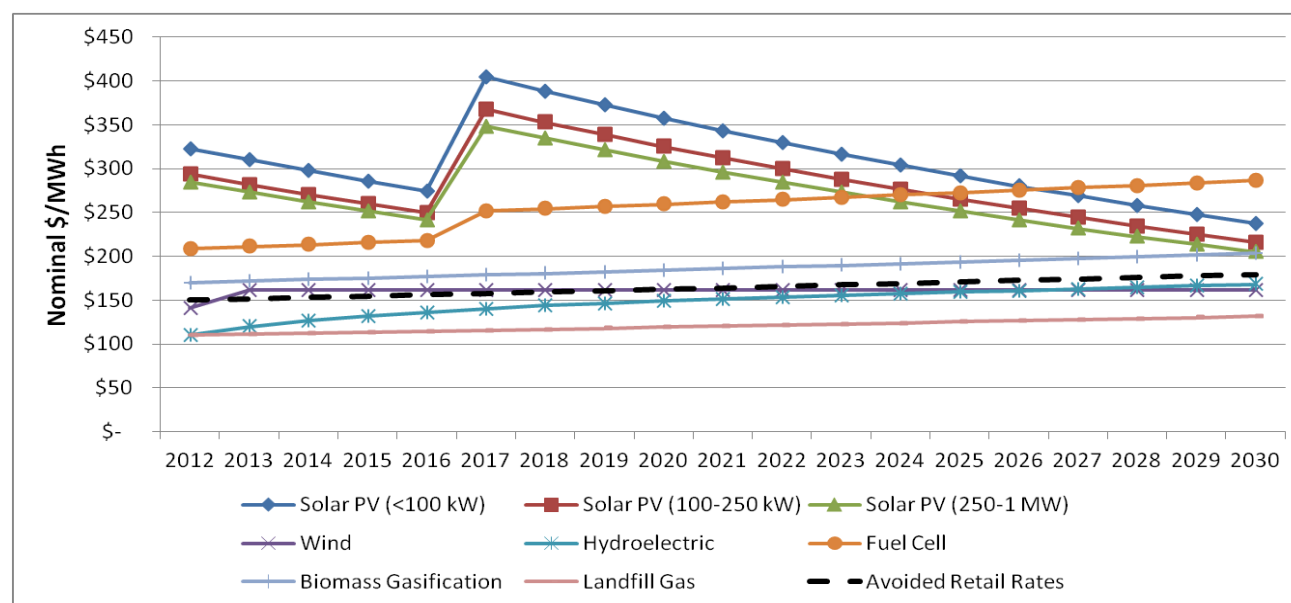
DEEP, along with the consultants at SEA, considered a number of scenarios to evaluate the impact of allowing large-scale hydro to fill a portion of the Class I RPS requirements. The analysis examined the impact of different levels of hydro under the existing Class I requirements as well as options which raised the RPS requirements after 2020. The reference case scenario illustrates the current RPS policy and expected contributions from existing programs. Presented below and summarized in Table 5 are four scenarios to illustrate the impact of this range of policy options:

- Scenario 1 establishes the combined Market and Contracted Class I RPS target at 20% by 2020, but adds a new Contracted (hydro) Tier that totals 5% of RPS eligible load. The Contracted Tier ramps up from an initial amount of 2.5% of load in 2014 to 5% by 2020. The traditional Class I (Market Tier) target peaks at 15% in 2020.

- Scenario 2 establishes the combined Market and Contracted Class I RPS target at 20% by 2020, but adds a new Contracted (hydro) Tier that reaches 10% of eligible load, dropping the requirement from traditional sources to 10% by 2020. The Contracted Tier ramps up from 5% in 2014 to 10% by 2020. The traditional Class I (Market Tier) target peaks at 10% in 2013 and remains flat thereafter.
- Scenario 3 extends Scenario 1, by establishing the combined Market and Contracted Class I RPS target at 20% by 2020 and 25% by 2025. A Contracted (hydro) Tier that ramps up from 2.5% in 2014 to 7.5% of load by 2025 is added. The traditional Class I (Market Tier) target reaches 15% by 2020 and 17.5% by 2025.
- Scenario 4 establishes the combined Market and Contracted Class I RPS target at 25.5% by 2020 and 30% by 2025. The ramp up of the Market Class I Tier is slowed to reach 20% by 2025 instead of 2020, with reductions replaced, and supplemented, by a Contracted (hydro) Tier starting at 2.5% in 2014 ramping up to 10% of eligible load by 2025.

**Table 5: Scenario Summaries**

RPS Demand Scenario	Market Tier Target in 2020	Market Tier Target in 2025	Contracted Tier
<b>Reference Case</b> <i>20% by 2020</i>	20%	20%	None
<b>Scenario 1</b> <i>20% by 2020 5% Contracted</i>	15%	15%	2014-2020 Ramp from 2.5% to 5%
<b>Scenario 2</b> <i>20% by 2020 10% Contracted</i>	10%	10%	2014-2020 Ramp from 5% to 10%
<b>Scenario 3</b> <i>25% by 2025 7.5% Contracted</i>	15%	17.5%	2014-2025 Ramp from 2.5% to 7.5%
<b>Scenario 4</b> <i>30% by 2025 10% Contracted</i>	17.5%	20%	2014-2025 Ramp from 5% to 10%

**Figure 6: Renewable Resource Cost Projections**<sup>33</sup>

Under the current RPS structure, the principle renewable options that are eligible for Class I and currently available are out-of state-wind, in-state solar, and fuel cells. Large hydroelectric power is not eligible for Class I under the existing RPS structure, but is currently available. DEEP compared the cost of using any of these different resource options to meet any projected shortfall, by estimating the over-market cost of each scenario, for a 100 MW block of power in 2025 (Table 6). A 100 MW block represents 876 GWh or approximately 14% of Connecticut's Class I RPS requirement in 2020.

In this analysis, DEEP found that large hydro—were it to become eligible for Class I—is potentially the lowest-cost of the options analyzed. In making this comparison, DEEP assumed that no premium would be paid above the market price for a contracted block of large scale hydropower, and that the 100 MW could be flowed over existing transmission lines. There is, however, considerable uncertainty about the cost to generate and deliver large hydro and the price that would be necessary to secure a long term contract. In response to comments highlighting that uncertainty, DEEP developed an additional scenario to model the impact of a premium on RPS compliance costs, and determined that the cost of large hydro would increase to approximately \$8.8 million if a 1 cent/kWh market premium is needed to secure a long term

<sup>33</sup> SEA Analysis

contract. Furthermore, DEEP concluded that the cost of 100 MW of large hydro would increase by an additional \$8.8 million for each 1 cent rise in the premium.

The analysis demonstrates that significant savings are possible by allowing large-scale hydro to fill a portion of the Class I requirement. Large hydro is the least cost option, followed by regional wind. As observed in Table 6, wind provides the greatest potential and lowest cost of the Class I eligible resources available in New England. This is represented by the proposed NESCOE procurement, which is assumed to be regional wind that is currently at the margin and needs a long-term contract to be viable in the market. This compares to \$48 million annually for the worst-case scenario spot market risk – that is, prices under shortage conditions that would approach the ACP price of 5.5 cents/kWh; \$22 to \$46 million for New England States Committee on Electricity (NESCOE) Procurement (regional wind under long-term contracts); and approximately \$88 million annually in 2025 for a mix of in-state solar and fuel cells.

**Table 6: Cost Sensitivities for Filling 100 MW Block by 2025, Single Year Compliance Cost (above market)**

Scenario	Supply Case	Spot (ACP Risk) <sup>1</sup>	NESCOE Procurement <sup>2</sup>	Additional In- State Programs <sup>3</sup>	Contracted Tier <sup>4</sup>
Reference	High Supply	\$48,180,000	\$44,564,748	\$88,767,797	\$0.00
Reference	Low Supply	\$48,180,000	\$46,188,852	\$88,767,797	\$0.00
Scenario 3	High Supply	\$48,180,000	\$22,363,252	\$88,767,797	\$0.00
Scenario 3	Low Supply	\$48,180,000	\$46,173,084	\$88,767,797	\$0.00
Scenario 4	High Supply	\$48,180,000	\$43,697,508	\$88,767,797	\$0.00
Scenario 4	Low Supply	\$48,180,000	\$45,826,188	\$88,767,797	\$0.00

1: = 100 MW multiplied by 8760 , multiplied by the ACP price of \$55

2: = 100 MW multiplied by 8760, multiplied by the Price Forecast in 2025

3: For the In-State Program methodology, DEEP modeled the LREC-ZREC and Residential Solar Investment Program at the same total budget ratios with the goal to reach 100 MW of capacity by 2025

4: Assumes that contract will be at no premium to market

In-state resources are generally the most expensive of the options most available. There are, however, other costs and benefits associated with these resources that must be considered. While solar and fuel cells generally cost the most, Connecticut benefits the most, in terms of employment and economic development, from development of in-state resources. In-state



facilities result in a growth of manufacturing and installation employment for renewable energy systems. Behind the meter projects, such as solar and fuel cells, help customers reduce their electric bills—increasing ratepayers' expendable income and making local businesses more competitive. In-state projects have an economic multiplier effect as a portion of these customer savings are then spent on local goods and services.

Wind and solar renewable resources produce no emissions, and fuel cells running on natural gas have very low emissions. There are differences in the time and magnitude that these resources produce power, but to the extent that they replace traditional generation they will each have the same ability to reduce harmful emissions such as CO<sub>2</sub>, NO<sub>2</sub> and SO<sub>x</sub>. The environmental impacts associated with building and transmitting power from distant hydro facilities in Canada or wind turbines in Maine, however, are greater than the comparatively benign impact of rooftop solar installations and fuel cells located in Connecticut.

The 2012 Integrated Resource Plan included estimates of the macroeconomic and employment impacts of various alternative resource strategies. The Department of Economic and Community Development (DECD) assisted in this effort by modeling the impact of additional energy resource investments in renewable resources and energy efficiency on employment, state GDP and state revenues. DECD developed its analysis using an input-output model, developed and maintained for the Connecticut Center for Economic Analysis, by Regional Economic Model, Inc. (REMI). The REMI simulations estimated the annual employment impact, over a 20-year period, of an annual \$10 million increase in investments in fuel cells and solar/small wind projects in Connecticut. REMI also simulated the impact of changes in electric rates of \$10 million and \$100 million. DEEP scaled these REMI results to the investment and rate impacts of the alternative RPS scenarios to estimate the annual impact on in-state jobs.

Table 7, below, shows the employment impact of each option, including direct, indirect and induced impacts. The analysis assumes out-of-state wind as the baseline. Importing 100 MW of large hydro would have a downward effect on electric rates, because large-scale hydro is the lowest cost option. In this analysis it is assumed that hydro will be purchased at the market price of power with no renewable premium. The cost of large hydro is estimated to be \$48.2 million less than the estimated cost of Spot Class I power (out-of-state wind) in 2025. The impact of lower electric rates associated with the large hydro also results in an increase of 295 jobs annually as consumers spend their savings on other in-state goods and services.



**Table 7: Projected In-State Employment Impact of Class I Generation Options**

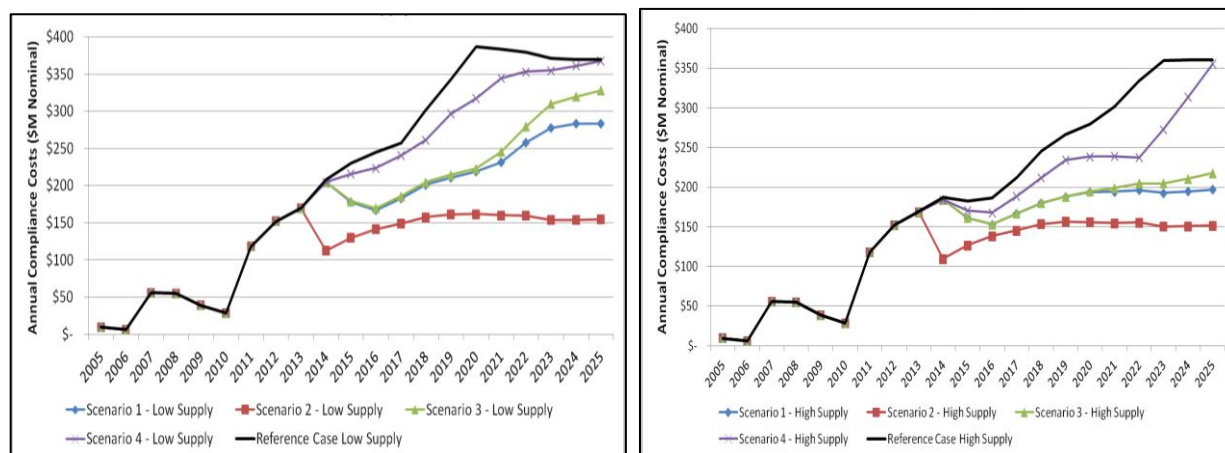
Employment Impact of Class I Generation Options (Jobs Created)			
	Baseline-wind	In-state Renewable	Large hydro
Rate Impact	0	-309.2	295.4
In-state Spending	0	979.6	0
Total Job Impact	0	670.4	295.4

In-state renewable investments in solar and fuel cell systems result in \$43 million in higher rates than the baseline wind scenario in 2025. DEEP estimates that higher rates associated with in-state renewable development would result in 309 fewer jobs annually than the wind option, however, this would be more than offset by an increase in employment due to the manufacturing and installation of solar and fuel cell systems. Three fuel cell manufacturing companies are located in Connecticut. Other Connecticut companies manufacture or assemble components used in these systems. DEEP estimates the direct impact of higher in-state spending would result in the addition of 980 jobs annually. The net result would be the addition of 670 jobs annually from the addition of 100 MW of in-state Class I renewable generation.

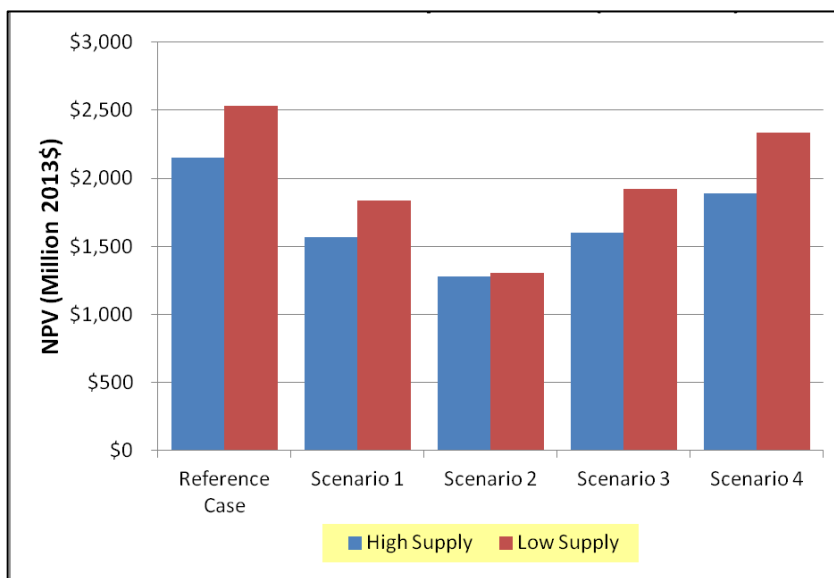
Each of the hydro options is projected to result in a lower overall cost than the Reference Case scenarios. In these scenarios, large hydro is assumed to displace a portion of Class I resources at no premium (i.e., the state would acquire and retire the associated RECs). In addition, the price of RECs declines due to a lower regional demand for Class I RECs. This combination of fewer REC purchases and lower REC prices decreases total costs in all of the hydro options when compared to the Reference Cases.

The savings under Scenario 1 and 3 are significant. The total cost over the ten year period from 2013 through 2022 for Scenario 1 is estimated to be \$1.8 to \$2.0 billion compared to \$2.4 to \$2.9 billion under the reference cases. It is estimated that Connecticut electric ratepayers could save from \$578 million to \$883 million or \$363 million to \$573 million on a present value basis under Scenario 1 over the ten year period. Annual savings are estimated to be approximately \$122 million to \$138 million annually for Scenario 1 in 2022 compared to the High and Low Supply Reference Cases.

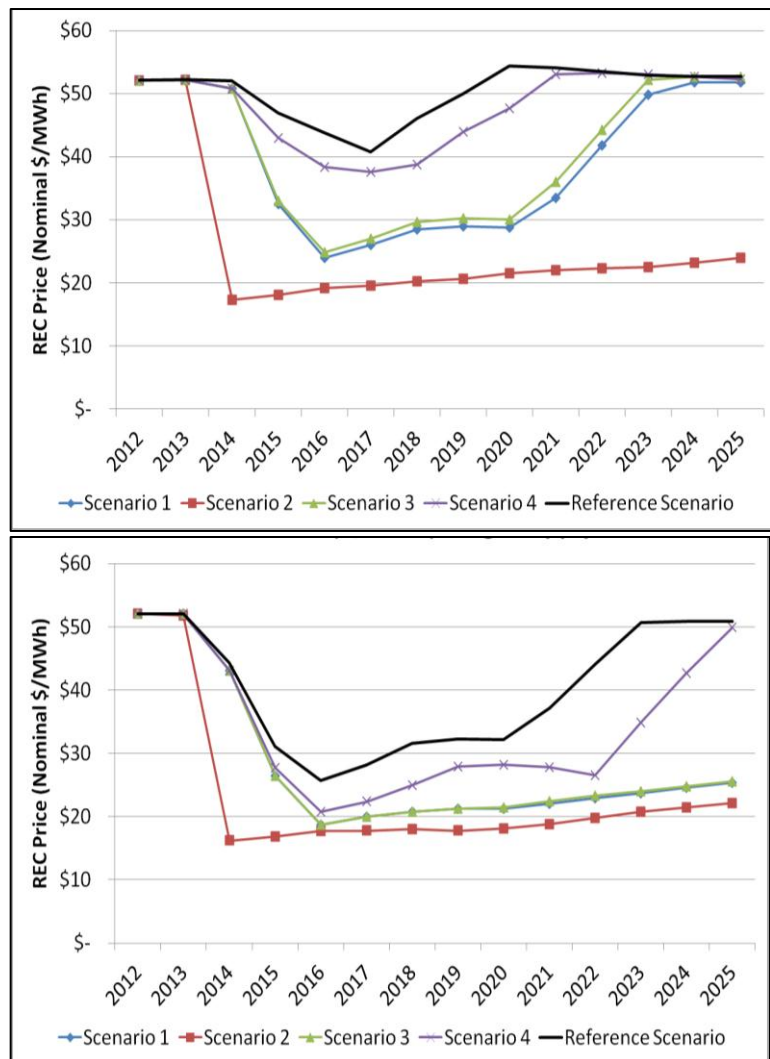
**Figure 8: Annual Compliance Costs - Low Supply vs. High Supply<sup>34</sup>**



**Figure 9: Net Present Value of Compliance Costs (2013-2025)**

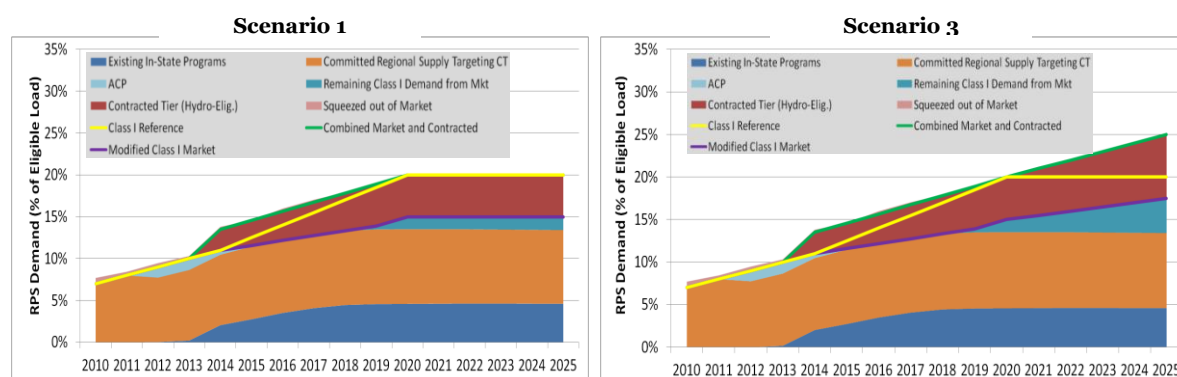


<sup>34</sup> Id.

**Figure 10: REC Price Forecast (\$/MWh) - Low Supply vs. High Supply<sup>35</sup>**

The overall cost of Scenario 3 is just slightly higher than Scenario 1 due to the increase in the RPS requirements from 20% in 2020 to 25% in 2025. However, the total cost of Scenario 3 is still considerably less than the Reference Cases. Under Scenario 3, Connecticut electric ratepayers could save from \$564-\$830 million or \$355-542 million on a present value basis over the ten year period from 2013 to 2022. DEEP estimates that savings of \$100 million to \$129 million annually in 2022, could result from Scenario 3 in comparison to the Reference Cases.

<sup>35</sup> SEA Analysis, "CT RPS Compliance Cost Scenario Analysis," slide deck

**Figure 11: RPS Demand - Scenario 1 vs. Scenario 3**<sup>36</sup>

A 5% reduction in the Class I RPS requirements in 2020 is approximately 1500 GWH.

Contracting for large hydro would avoid the need for approximately 490 MW of wind power at a 35% capacity factor, but would only require 171 MW of transmission capacity if the power was delivered evenly across all hours.

Under these scenarios there is no disruption to existing projects, or those under construction. Demand for the traditional Market Tier continues to grow, which provides adequate demand for the projected supply from Connecticut's existing in-state renewable energy programs. However, a sub tier made up of 5% contracted large-scale hydro by 2020 would take up almost all of the incremental RPS requirements not filled by in-state programs, displacing any potential regional resources currently in the development pipeline or that might otherwise be developed in the next five or six years. In Scenario 3, there would be demand for additional resources after 2020, which could be filled with regional or additional in-state Class I resources after. The exact amount of demand for additional Class I resources is unknown as the portions of the RPS that are displaced by large hydro are offset to some degree by tightening the Class I requirements for "legacy" renewable generation and disallowing resources that are counted toward renewable obligations in other states.

In order to examine the sensitivity of the savings DEEP conducted additional analysis in response to stakeholder comments. In one analysis, DEEP examined the savings of Option 3 if the large hydro must be purchased at a 1 cent/kWh premium to market rates. In the second analysis, DEEP examined the impact that an expanded energy efficiency programs conservation plan would have on the savings. For this analysis, DEEP utilized the level of energy efficiency

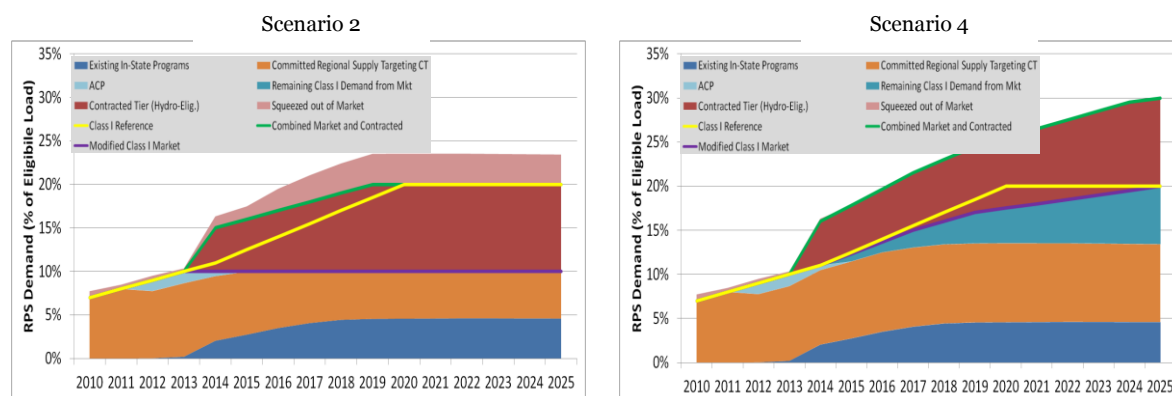
<sup>36</sup> SEA Analysis, "CT RPS Compliance Cost Scenario Analysis," slide deck

investments evaluated as part of the 2012 IRP to consider the load reduction impacts of efficiency investments at this level. Both scenarios reduce the estimated savings that could result from the contracted tier under Scenario3, however meaningful savings still occur.

Under the 1 cent/kWh premium scenario, total savings over the 10 year period from 2013-2022 decline from \$830 million to \$708 in the low case and from \$564 million to \$442 million in the high case. This is a reduction of \$122 million or about 15% on a nominal basis and \$82 million on a NPV basis. Annual savings are estimated to decline from \$100-\$129 million annually in 2022 to \$81 -\$110 million annually.

The 2012 IRP and Comprehensive Energy Strategy for Connecticut call for expanded conservation spending increasing the electric conservation budget from approximately \$105 million annually to \$206 million. Load was forecasted to grow at an annual rate of .2% in the reference cases. This growth rate does not include the full impact of the expanded conservation effort. DEEP conducted an additional analysis using .4% load growth to examine the full impact of the expanded conservation plan on Scenario 3. Lower load reduces the amount of REC's that must be purchased to meet the RPS requirements, thereby reducing compliance costs. The analysis indicates that compliance costs would be lowered by less than \$10 million in 2022 in the high and low cases under Scenario 3 with more conservation. The annual savings and total savings over the ten year period, remains very similar to those estimated in the base cases if both the reference case and Scenario3 cases are adjusted for higher conservation (Appendix B-2).

Scenario 2 is similar to Scenario 1, but a larger portion of the Class I requirement is allowed to be filled with large hydro. Scenario 2 is also based on the current 20% by 2020 RPS. In this scenario, however, the Contracted Tier ramps up from 5% in 2014 to 10% of the Class I requirement in 2020. This represents 100% of the current incremental growth in the requirements from 2013-2020 which is the equivalent of 1088 MW of wind. The traditional Class I Market Tier peaks at 10% in 2013 and stays at that level through 2020. Of the scenarios analyzed, this Scenario 2 results in both the lowest annual and total cost, but also has the greatest impact on the Class I market, squeezing out existing resources and all new facilities currently under development.

**Figure 12: RPS Demand - Scenario 2 vs. Scenario 4<sup>37</sup>**

Large hydro could be used to meet Connecticut's energy needs without being eligible to receive Class I RECs and would be considered "outside" of the RPS. Large hydro could be used to meet base load needs or peaking requirements and provide a hedge against high or rising energy prices. Allowing large hydro, outside of the RPS, could help meet our energy and capacity needs would also reduce prices in the energy and capacity markets. Providing a long term contract might encourage the development of transmission lines capable of bringing more power from Canada into New England in the future. It would not, however, provide the benefit of fewer Class I REC purchases or reduced REC prices.

Scenario 4, which includes a large hydro Contracted Tier, provides an example of how large hydro, outside of the RPS, could work. In Scenario 4, the Combined Market and Contracted Tier increases from 20 to 25% in 2020 and to 30% by 2025, but only a small portion of the Contracted Tier is substituted for existing Class I requirements. The result is little disruption to the Class I market, but also the least savings of the scenarios examined. Under that scenario, REC prices would remain high and Connecticut would still be faced with possible supply shortages in the future.

### **New Proposal: Flexible Approach to Procuring Large Scale Hydropower**

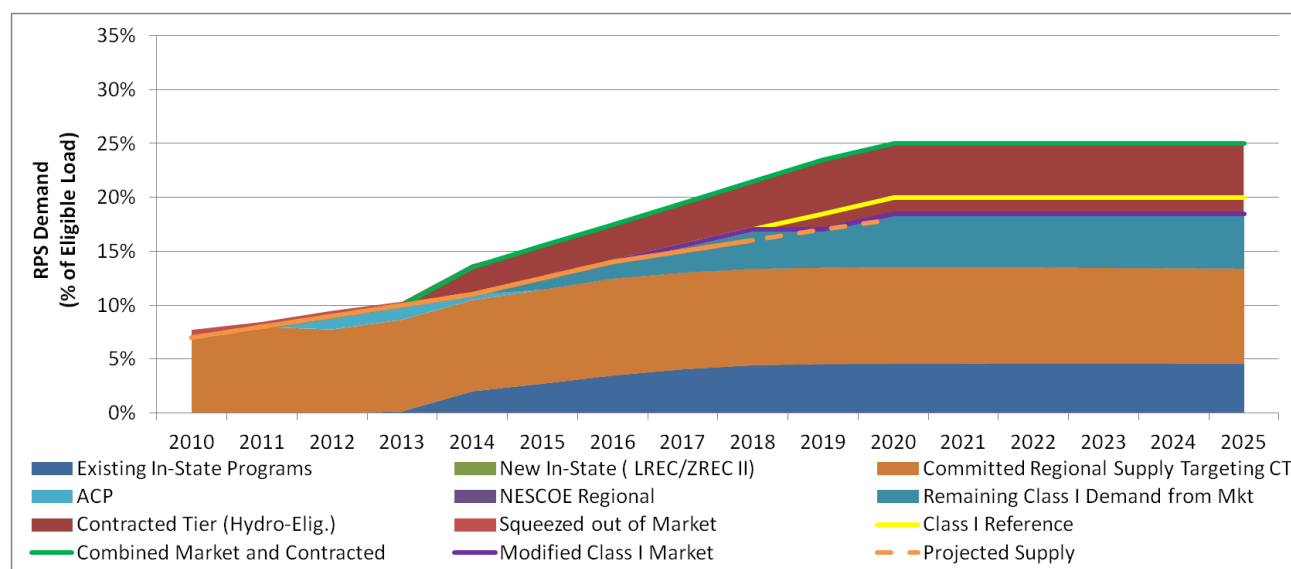
There is considerable uncertainty about the timing of the need for additional Class I-eligible generation, as the supply-demand balance depends on a range of contingencies regarding the successful development of planned generation and transmission, retirements or changes to eligibility of existing resources, as well as policy decisions in each New England state and at ISO-

<sup>37</sup> SEA Analysis, "CT RPS Compliance Cost Scenario Analysis," slide deck.

NE and the federal government. In the presence of such uncertainties, Connecticut may be better served by maintaining a degree of flexibility to adjust the RPS compliance targets if existing Class I renewable supply proves to be inadequate, rather than making firm adjustments to the Class I RPS requirements through the use of a contracted sub-tier described above.

For example, if a material ACP reliance or supply shortage is experienced or expected for a sufficiently long consecutive period that suggests a long-term divergence of supply and demand (i.e., inability for sufficient supply to respond to price signals to meet demand), the ramp-up of Class I targets could be slowed and replaced by limited increments of additional large scale hydropower. This option most resembles Scenario 4 in terms of likely costs. DEEP analyzed this type of flexible mechanism on a qualitative basis only, and the results are illustrated by Scenario 5 in Figure 13. Scenario 5 assumes a supply shortage in 2017 and 2018, with a continued shortage projected for the next several years. In these circumstances, the flexibility mechanism could be utilized to allow a portion of Class I growth to be filled with the large scale hydropower.

**Figure 13 Scenario 5: Illustrative Example of Conditional Flexibility Mechanism**



Rather than creating a fixed sub tier at this time, this study recommends adopting a conditional flexibility mechanism utilized to allow a portion of Class I growth to be filled with large scale hydropower, but only if a significant amount of Class I RPS requirements are being met with ACP payments. DEEP would conduct a procurement open to both Class I resources and large-scale hydropower with the goal of entering into a long term contracts. If successful in the bidding process, large scale hydro resources would be procured as a hedge strategy against increased REC prices and insufficient renewable supply. However, large hydro would not be

used to fill Class I RPS requirements unless a shortage develops. If this occurs, DEEP would verify if a shortage has developed and is likely to continue. In the event that DEEP concludes that a shortage is likely to continue, it would have the flexibility to allow large hydro to fill a portion of the Class I requirements. The Class I requirements could then be reduced for all suppliers by a corresponding amount. The capacity and energy would be sold back into the markets, and large hydro would not be eligible for REC's.

This proposal will provide an opportunity for Class I projects to meet the current RPS standards while at the same time creating a hedge to protect ratepayers from high RPS compliance costs if they cannot be developed in time. This can be an effective way to make minor market adjustments in a way that is fully transparent to market participants. Because it is unclear if or when (and to what extent) such a shortfall might occur, it is difficult to estimate the precise RPS compliance cost savings that could occur as a result of this mechanism. However, such flexibility can help ensure that Connecticut ratepayers are protected from unreasonably high costs while still making adequate progress towards achieving clean energy goals under a range of future circumstances.

Additional hydro power would help all New England meet our energy and capacity requirements and should also help Connecticut meet its requirements under the Global Warming Solutions Act. DEEP could solicit proposals from hydropower facilities including those located in Newfoundland and Labrador to qualify, which would increase potential competition. DEEP would be responsible for the procurement of any large hydro generation under a long term contract. Projects could be evaluated on price and non-price variables. While the objective is to obtain long term contracts, there is no obligation to enter into contracts so if the price does not seem reasonable over the life of the contracts. The products purchased and contract duration could vary and therefore DEEP recommends flexibility in these areas.

DEEP envisions conducting a transparent and competitive process to select the projects. Connecticut's EDCs, Connecticut Light & Power (CL&P) and The United Illuminating Company (UI), would sign the contracts and administer them. All of the products would be used to benefit all electric ratepayers of the EDCs. The cost of the contracts could be passed on to these electric ratepayers through a fully reconciling nonbypassable charge. Any associated environmental attributes of large scale hydro which would not be tradeable in the GIS market could simply be retired. Any capacity or energy would be sold in the markets with any cost/benefits passed on to all electric ratepayers through the same nonbypassable rate. A detailed discussion of the pros



and cons of the eligibility and contract options is included in Appendix I (Section 6 Transaction Structure).

Today, less than 4% of Connecticut's electricity is generated by hydropower. Increasing that proportion would help diversify Connecticut's power mix and provide some insurance against possible shortages, disruptions, and outages. A long-term hydropower contract could also be structured to create a hedge against unexpected rises in gas prices. To the extent that large-scale hydro generation is allowed to fill a portion of Class I RPS requirements and helps avoid supply shortage and compliance through the ACP, Connecticut's dependence on fossil fuels—particularly natural gas—will be reduced consistent with the goals of the RPS. Lower natural gas demand for electric generation would provide some relief to tight pipeline capacity during peak hours, or cold weather snaps improving electric reliability. Low-cost hydro generation is suited to meet base load needs but also might provide added value if used to meet peak demands and balance the intermittent output of other renewable energy sources.

### **Options for Long-Term Power Purchase Agreements**

The scenarios analyzed and presented above are just a sample of possible approaches that could be taken to meet Connecticut's Class I renewable energy objectives at a lower cost. The mix of resources and the resulting cost to ratepayers varies significantly depending on the approach. If Connecticut maintains current requirements and continues to rely on spot market purchases of RECs, it is likely that that it will be increasingly difficult to meet our RPS requirements, increasing the risk of shortage and payment of the ACP within a decade. To the extent that new resources are deployed, wind from out-of-state sources (which may also require transmission investments) will dominate new capacity additions not provided by existing in-state programs. By taking a more active role in the market, Connecticut can (1) increase the diversity of its electric resources thereby increasing reliability and providing a hedge against future higher fossil fuel prices; (2) reduce harmful greenhouse gas and criteria pollutant emissions; and (3) achieve these benefits without burdening ratepayers with high costs that yield limited benefits.

Entering into long-term Power Purchase Agreements can accomplish multiple objectives. Empirically, they have proven critical to facilitating the financing of large-scale renewable energy facilities (potentially including associated transmission). Long-term PPAs can also function as a hedge, reducing ratepayer exposure to the cost of shortages, either through direct payments of ACPs, or payments for RECs at market prices approaching the ACP during periods of inadequate supply. If supply can be purchased at reasonable price, such PPAs can have a

similar hedge impact from a ratepayer perspective whether the resource is new, or already operating. Further, if a PPA is executed at a bundled, levelized price (or the financial equivalent through a contract-for-differences), with the expectation of escalating energy prices (including the increasing price on carbon emissions), the implicit cost of RECs could come down over time, becoming most attractive during the period when the compliance cost analysis shows highest risk exposure to high Class I REC costs. The lower the cost of the hedge, the more likely and more substantial the potential benefit to ratepayers will be.

Timely authorization for DEEP's to conduct procurements for Class I resources would enable the state to harmonize its procurement with efforts by other states in the region to contract for the lowest-cost regional renewable supply. To explore the impact of such a strategy, whether in addition to, or in place of, other alternatives considered in this study, DEEP conducted additional sensitivity analyses considering a range of realistic bundled PPA prices likely to be garnered in the market, their volumes and durations. The results of these analyses are described below.

### **Long-Term PPAs for New Wind Projects**

The focus of DEEP's consideration of long term PPAs has been for new Class I resources. While the annual cost (in 2025) of a 100MW block of the marginal wind resource commencing commercial operation in 2025 was assessed as part of DEEP's original analysis (under a hypothetical NESCOE-type procurement), DEEP interest and stakeholder comments warranted a more detailed investigation of the cost impacts of procuring large blocks of regional Class I resources in the near term. In this sensitivity analysis, DEEP tested the effect of such a contract on both the Reference Case and Scenario 3, in each case assuming a fixed price contract for a bundled product including energy, capacity and RECs. Prices of \$75, \$85 and \$95/MWh (nominal levelized dollars), in line with recent market experience were tested. These prices were chosen based on recent experience in the market. Other competitive solicitations in New England (with Federal incentives, not requiring major network transmission investment, and shorter PPA duration) suggest that the lower end of the range may be viable for similar projects. Those requiring more significant transmission investments may require contract prices closer to the upper end of this range. The analysis assumed that the PPA(s) would begin delivery starting on 1/1/2016 and span 15-20 years, well beyond the time scope of this study. Finally, PPA sizes of 150, 300 and 450 MW of wind were tested.

Implicit REC prices for each contract price were calculated by subtracting the commodity market value (energy, capacity<sup>38</sup>) from the total bundled PPA price. In the table below, the results are compared to the projected REC prices for the Reference Case and Scenario 3 under conditions of high and low supply. The contracts are particularly attractive under the low supply case and in the later years of the analysis. In addition, the contracts serve as a better hedge under the Reference Case than Scenario 3, as market REC prices (against which the PPAs are measured) are projected to be substantially lower under the Contracted Class I Tier scenario due to much lower market RPS demand.

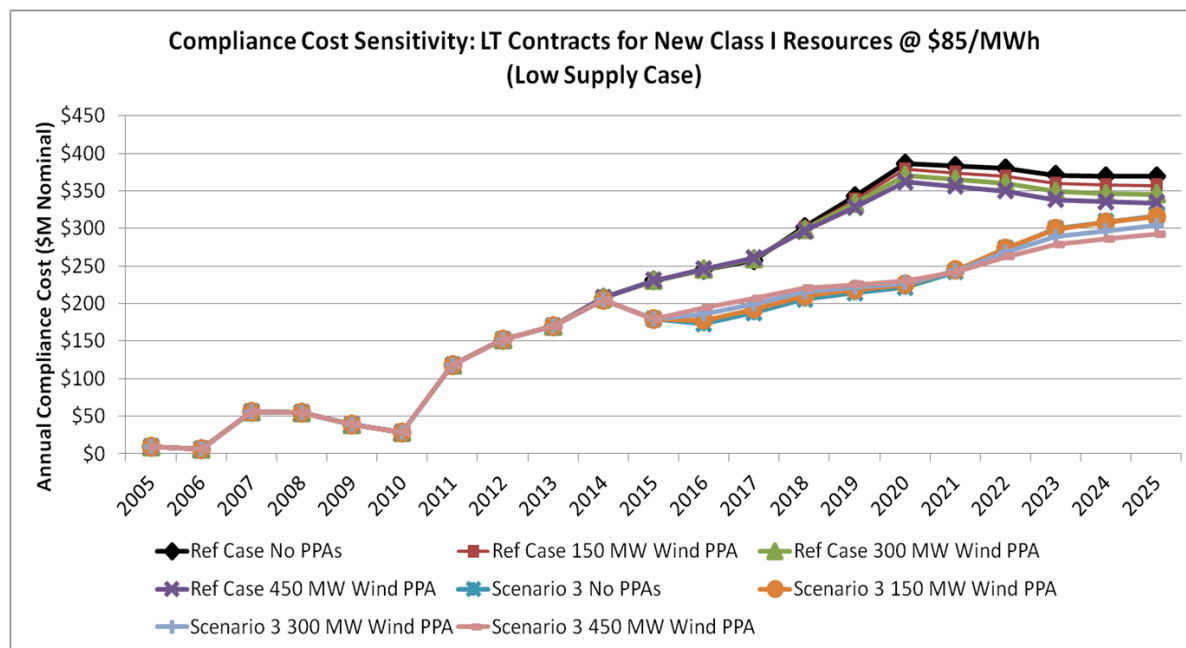
**Table 8. Class I RPS REC Price Projection: Reference Case & Scenario 3 Comparison with LT PPAs for New Wind (\$/MWh)**

Year	High Supply		Low Supply		Bundled Wind PPAs		
	Reference Case	Scenario 3	Reference Case	Scenario 3	@\$75/MWh	@\$85/MWh	@\$95/MWh
2013	\$52.06	\$52.03	\$52.25	\$52.14	\$32.08	\$42.08	\$52.08
2014	\$44.27	\$43.04	\$51.98	\$50.83	\$33.23	\$43.23	\$53.23
2015	\$31.12	\$26.45	\$46.94	\$32.98	\$33.59	\$43.59	\$53.59
2016	\$25.69	\$18.73	\$43.79	\$24.82	\$34.08	\$44.08	\$54.08
2017	\$28.12	\$19.99	\$40.77	\$27.02	\$33.26	\$43.26	\$53.26
2018	\$31.55	\$20.78	\$46.01	\$29.68	\$31.70	\$41.70	\$51.70
2019	\$32.26	\$21.24	\$49.99	\$30.22	\$28.48	\$38.48	\$48.48
2020	\$32.16	\$21.42	\$54.39	\$30.01	\$25.37	\$35.37	\$45.37
2021	\$37.18	\$22.40	\$54.12	\$35.98	\$23.41	\$33.41	\$43.41
2022	\$44.11	\$23.31	\$53.53	\$44.22	\$20.88	\$30.88	\$40.88
2023	\$50.71	\$24.01	\$52.94	\$52.16	\$18.39	\$28.39	\$38.39
2024	\$50.87	\$24.76	\$52.73	\$52.71	\$17.22	\$27.22	\$37.22
2025	\$50.87	\$25.53	\$52.73	\$52.71	\$16.03	\$26.03	\$36.03

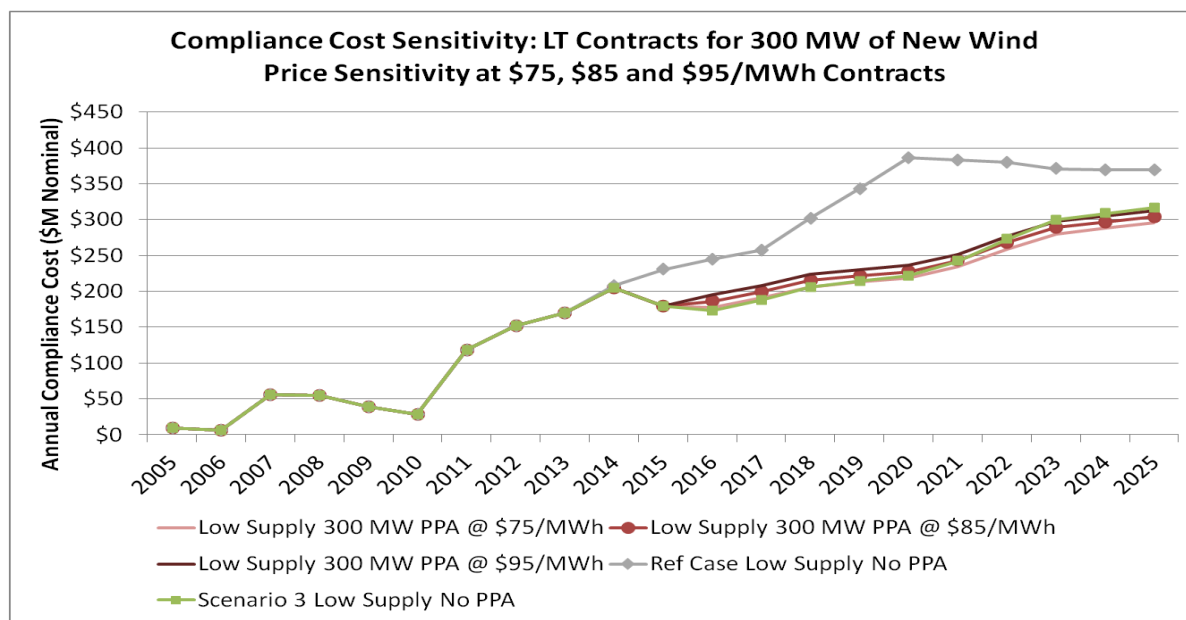
These REC prices were used to evaluate annual compliance costs at several PPA sizes. The \$85/MWh option was tested for all sizes as a middle ground, and additional price sensitivities were run to show the added cost or benefit of varying contract prices. Figure 1 illustrates the annual compliance cost forecast at \$85/MWh (under low supply conditions), while Figure 2 shows the compliance costs for a 300 MW PPA across all contract prices.

<sup>38</sup> Because potential bidders for these contracts are assumed to be large wind projects in northern Maine, capacity value was derated by 50%, given the uncertainty facing the capacity market in this region.

**Figure 14. Class I RPS Annual Compliance Cost Projection: Reference Case & Scenario 3 Sensitivity with New Wind PPA @ \$85/MWh, Varying PPA Sizes (Low Supply Case)**



**Figure 15. Class I RPS Annual Compliance Cost Projection: Scenario 3 Sensitivity with 300 MW PPA for New Wind @ \$75, \$85 and \$95/MWh (Low Supply Case)**



When both \$85/MWh and \$75/MW PPAs are considered in net present value terms (assumed discount rate = 7.5%), there is a clear potential for savings under the reference case. However, under Scenario 3, the NPV of compliance cost over the first 10 years of the contract (the analysis limits) is actually higher under the PPA sensitivity, assuming an \$85/MWh PPA price, and only

slightly cheaper in the \$75/MWh case. For each of these calculations, NPV is measured between 2013 and 2025 (as opposed to 2022, which was used to bound the value calculations of the original scenario analyses) to try and capture the PPA's value as a hedge against expected high REC prices in later years. If the analysis was extended for the full duration of the contracts, it is likely that the benefits would be significantly higher in both cases, even when discounted.

**Table 9. NPV of Projected Class I RPS Compliance Costs 2013-2025: Reference Case & Scenario 3 Sensitivity LT PPAs for New Wind @ \$85/MWh (Low Supply Case)**

	Ref Case Low Supply No PPAs	Ref Case Low Supply 150 MW Wind PPA	Ref Case Low Supply 300 MW Wind PPA	Ref Case Low Supply 450 MW Wind PPA	Scenario 3 Low Supply No PPAs	Scenario 3 Low Supply 150 MW Wind PPA	Scenario 3 Low Supply 300 MW Wind PPA	Scenario 3 Low Supply 450 MW Wind PPA
NPV 2013-2025 (Million 2013\$)	\$2,532	\$2,498	\$2,464	\$2,430	\$1,906	\$1,921	\$1,922	\$1,923

**Table 10. NPV of Projected Class I RPS Compliance Costs 2013-2025: Reference Case & Scenario 3 Sensitivity LT PPAs for New Wind @ \$75/MWh (Low Supply Case)**

	Ref Case Low Supply No PPAs	Ref Case Low Supply 150 MW Wind PPA	Ref Case Low Supply 300 MW Wind PPA	Ref Case Low Supply 450 MW Wind PPA	Scenario 3 Low Supply No PPAs	Scenario 3 Low Supply 150 MW Wind PPA	Scenario 3 Low Supply 300 MW Wind PPA	Scenario 3 Low Supply 450 MW Wind PPA
NPV 2013-2025 (Million 2013\$)	\$2,532	\$2,472	\$2,413	\$2,353	\$1,906	\$1,896	\$1,871	\$1,846

This sensitivity analysis shows that a PPA strategy is a more effective substitute than complement to the Scenario 3 Contracted Class I Tier strategy at the higher end of the PPA price range, whereas the combination of these tactics can provide additive benefits at the lower end of the PPA price range. The probability of soliciting PPAs at prices is expected to be higher if PPAs are solicited sooner, and for longer duration. The low end of the contract price range analyzed here are most likely to be achieved with access to Federal tax incentives (PC or ITC) slated to expire for projects not under construction by the end of 2013. Contract lengths of 15-20 years should result in lower prices than the 10-15 year PPAs offered in neighboring states.

### Long-Term PPAs with Currently Operating Projects

The potential impact of extending long term PPA opportunities to resources already in commercial operation was also analyzed. PPAs for existing generators could be used either as an alternative, or compliment, to biomass eligibility changes, as PPAs would provide the revenue stability necessary for generators to ensure continued operation for a sufficient period to ensure the reliability of the system during a biomass phase out while also hedging ratepayer cost. To

quantify this cost or benefit, an analysis was conducted similar to the analysis of PPA value for new resources.

In this sensitivity, PPAs again comprised a bundled product consisting of energy, capacity and RECs. Implicit REC prices for each contract price were calculated by subtracting the commodity market value (energy, capacity<sup>39</sup>) from the total bundled PPA price. PPA prices of \$75, \$90, and \$100/MWh were evaluated at sizes of 150 and 300 MW. The \$75/MWh price range would be more accessible for projects that don't have to pay for fuel (i.e. existing wind, hydro, landfill gas), while operating biomass plants may need more than \$75 to break even on fuel and short-run operating costs. It is more likely that these plants would require prices in the \$90 range to justify continued operation or retrofits. This is in line with recent market experience.<sup>40</sup>

This analysis also differed from the assessment of new resource PPAs in contract duration. Here, a term of up to 10 years was assumed, beginning either on 1/1/2016, or alternatively, on 7/1/2013 (reflecting an expedited procurement intended to relieve short term ACP risk). The table below compares REC prices under each PPA price along with original projects for the Reference Case and Scenario 3 under conditions of low and high supply. Like the new resource PPA results, the hedge value is greatest when compared to the Reference Cases and is particularly high in the later contract years. Unlike the new resource analysis, these existing resources would be available immediately, which warrants the timing sensitivity described above.

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<sup>39</sup> Unlike new wind resources, the participation of these generators in the FCM market is not in question.

<sup>40</sup> The Ryegate (VT) biomass plant recently secured a bundled PPA for \$97/MWh (levelized equivalent) in a non-competitive procurement. A competitive solicitation issued by DEEP would likely drive prices lower than this reference point.

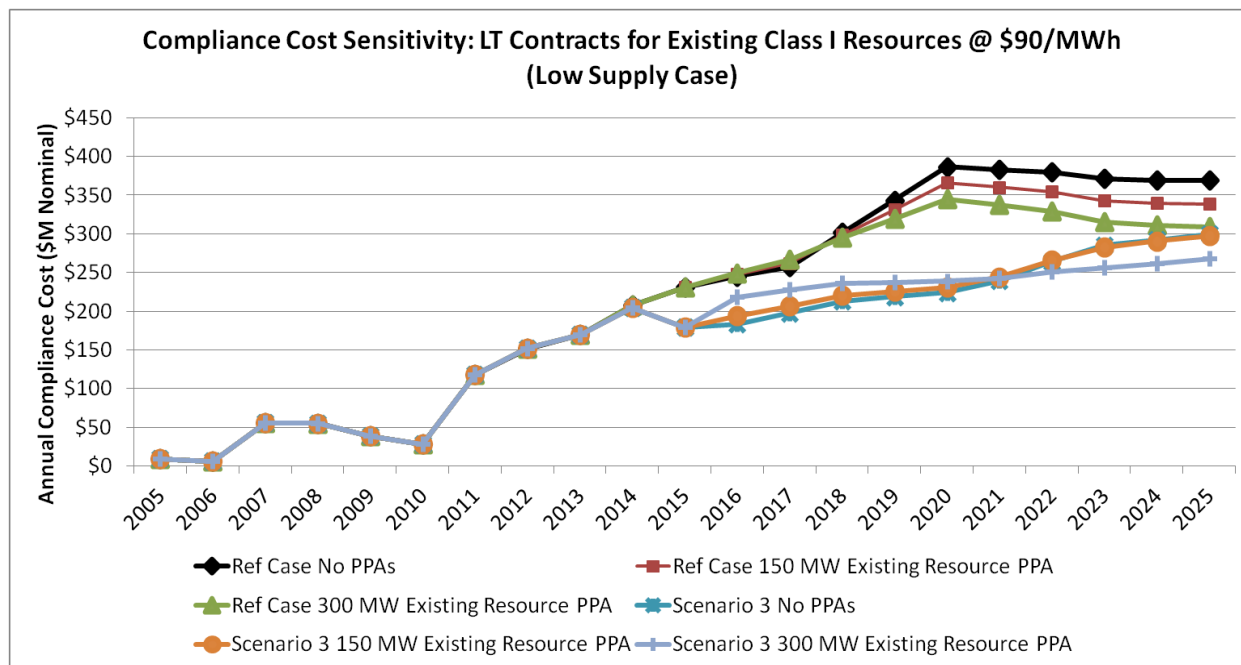
**Table 11. Class I RPS REC Price Projection: Reference Case & Scenario 3 Comparison with LT PPAs for Existing Resources (\$/MWh)**

Year	High Supply		Low Supply		<i>Bundled Operating Biomass (or other) Contract</i>		
	Reference Case	Scenario 3	Reference Case	Scenario 3	@\$75/ MWh	@\$95/ MWh	@\$100/ MWh
2013	\$52.06	\$52.03	\$52.25	\$52.14	\$28.67	\$43.67	\$53.67
2014	\$44.27	\$43.04	\$51.98	\$50.83	\$29.76	\$44.76	\$54.76
2015	\$31.12	\$26.45	\$46.94	\$32.98	\$30.06	\$45.06	\$55.06
2016	\$25.69	\$18.73	\$43.79	\$24.82	\$30.49	\$45.49	\$55.49
2017	\$28.12	\$19.99	\$40.77	\$27.02	\$29.61	\$44.61	\$54.61
2018	\$31.55	\$20.78	\$46.01	\$29.68	\$28.06	\$43.06	\$53.06
2019	\$32.26	\$21.24	\$49.99	\$30.22	\$24.84	\$39.84	\$49.84
2020	\$32.16	\$21.42	\$54.39	\$30.01	\$21.73	\$36.73	\$46.73
2021	\$37.18	\$22.40	\$54.12	\$35.98	\$19.77	\$34.77	\$44.77
2022	\$44.11	\$23.31	\$53.53	\$44.22	\$17.24	\$32.24	\$42.24
2023	\$50.71	\$24.01	\$52.94	\$52.16	\$14.75	\$29.75	\$39.75
2024	\$50.87	\$24.76	\$52.73	\$52.71	\$13.58	\$28.58	\$38.58
2025	\$50.87	\$25.53	\$52.73	\$52.71	\$12.39	\$27.39	\$37.39

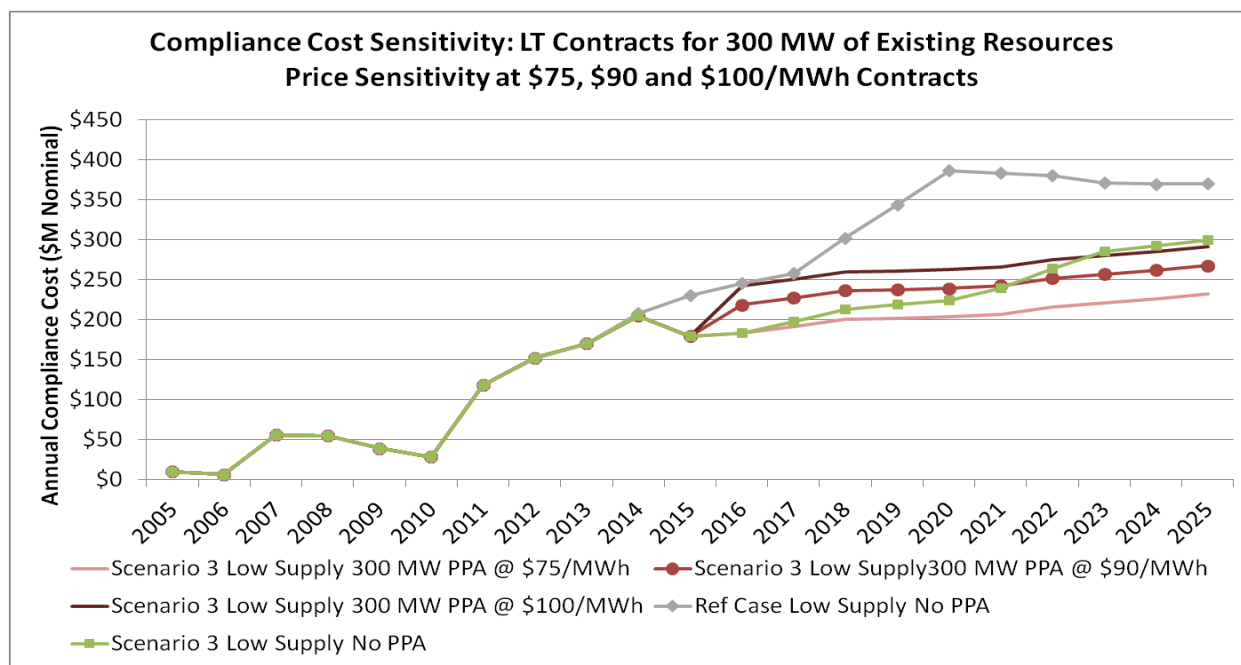
The annual compliance cost results are presented in Figures 3 and 4 below, reflecting the cost/benefit of varying contract sizes and contract prices. Each reinforces the relative benefit of hedging against the Reference Case over Scenario 3, which is only projected to achieve consistent savings under the lowest price case (which would exclude existing biomass).



**Figure 16. Class I RPS Annual Compliance Cost Projection: Reference Case & Scenario 3 Sensitivity with Varying LT PPAs for Operating Resources @ \$90/MWh (Levelized) Beginning 1/1/16 (Low Supply Case) (\$M Nominal)**



**Figure 17. Class I RPS Annual Compliance Cost Projection: Reference Case & Scenario 3 Sensitivity with 300 MW PPA for Operating Resources @ \$75, \$90 & \$100/MWh (Low Supply Case)**





The timing of the contract was evaluated on a net present value basis, as summarized by the tables below. Table 5 shows the cost/benefit of each contract size (at \$90/MWh) beginning 1/1/2016, consistent with the results presented above. Table 6 shows the same results for contracts beginning 7/1/2013, shifting the value of the hedge to the near-term at the expense of long-term savings (due to the 10-year PPA duration assumption). In both sensitivities, PPAs under the Reference Case show modest savings, while PPAs under Scenario 3 actually increase compliance costs slightly. It should be noted, however, that if the alternative to PPAs is a loss of a significant portion of the biomass fleet, the relative value of the hedge PPAs will be much greater.

**Table 12. NPV of Projected Class I RPS Compliance Costs 2013-2025: Reference Case & Scenario 3 Sensitivity Varying LT PPAs for Operating Resources @ \$90/MWh (Levelized) Beginning 1/1/16 (Low Supply Case)**

	Ref Case, Low Supply No PPAs	Ref Case, Low Supply 150 MW PPA	Ref Case, Low Supply 300 MW PPA	Scenario 3, Low Supply No PPA	Scenario 3, Low Supply 150 MW PPA	Scenario 3, Low Supply 300 MW PPA
NPV 2013-2025 (Million 2013\$)	\$2,532	\$2,449	\$2,367	\$1,902	\$1,932	\$1,944

**Table 13. NPV of Projected Class I RPS Compliance Costs 2013-2025: Reference Case & Scenario 3 Sensitivity Varying LT PPAs for Operating Resources @ \$90/MWh (Levelized) Beginning 7/1/13 (Low Supply Case)**

	Ref Case, Low Supply No PPAs	Ref Case, Low Supply 150 MW PPA	Ref Case, Low Supply 300 MW PPA	Scenario 3, Low Supply No PPA	Scenario 3, Low Supply 150 MW PPA	Scenario 3, Low Supply 300 MW PPA
NPV 2013-2025 (Million 2013\$)	\$2,532	\$2,466	\$2,401	\$1,902	\$1,965	\$2,009

## Options for Expanding the Class I RPS Targets

The 2011 legislation specified that DEEP's review contain an analysis of certain elements of the RPS including the feasibility of increasing the RPS requirements. The current RPS requirements for all resource classes end in 2020. Increasing the demand for Class I REC's by increasing the RPS requirements will increase the compliance costs for the RPS. Higher requirements will require more renewable generation which could also raise REC prices adding to compliance costs and the possibility of a shortage. DEEP conducted an analysis to estimate the cost of increasing the Class I RPS requirements from 20% in 2020 to 25% in 2025. The analysis estimates that annual compliance costs could increase by \$82 to \$95 million by 2025 from increasing the Class I RPS requirements to 25% in 2025. Higher Class I RPS requirements could add \$238 to \$270 million to ratepayers electric bills over the five year period from 2020 through 2025. If, however, increasing the targets for Class I resources is combined with

modifications that would allow large hydro to fill a portion of the Class I RPS requirements compliance costs might still be lower than the reference case scenarios. See Figure 8

Since DEEP does not recommend a portion of Class I be filled with large hydro, DEEP would recommend no action on expanding Class I at this time. DEEP will examine this issue further, reassess the cost implications and provide a recommendation regarding the extension of RPS requirements at the time of the 2015 IRP.

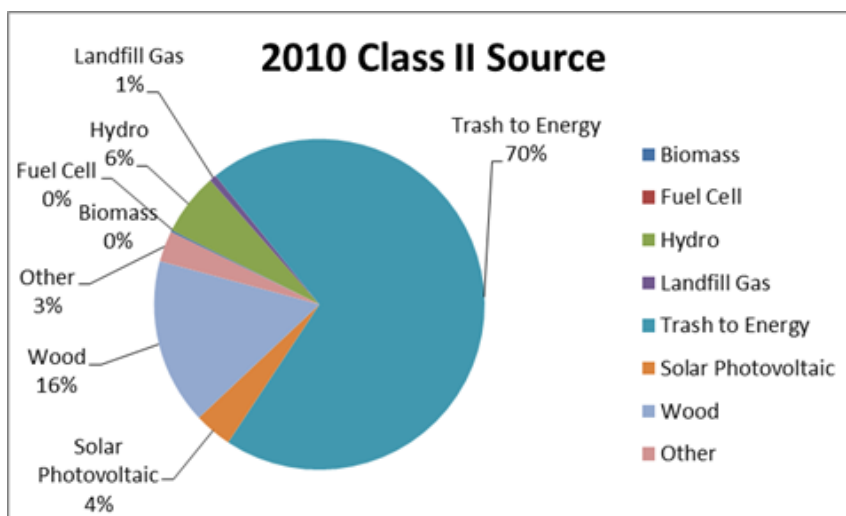
## CLASS II RESOURCES

Pursuant to Conn. Gen. Stat. §16-1(a) (27), Class II renewable energy sources include energy derived from:

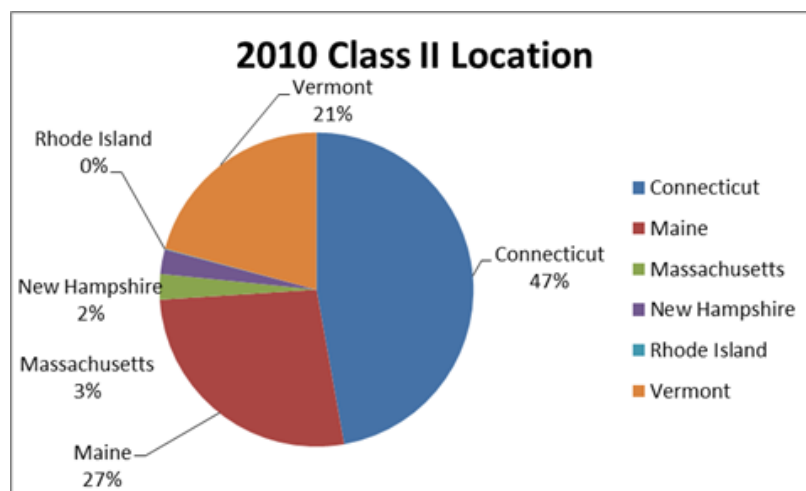
- resource recovery facilities;
- a biomass facility that began operation before July 1, 1998, provided the average emission rate for such facility not exceeding 0.2 pounds of NO<sub>x</sub> per million BTU of heat input for the previous calendar quarter; or
- a run-of-the-river hydropower generating facility up to five megawatts that began operation prior to July 1, 2003.

The Class II requirement was initially set at 3% and remains constant through 2020. There are currently 122 generating plants across New England that meet the Connecticut Class II requirement, with a total capacity of 670 MW. More projects could qualify, but do not apply for eligibility because of the low Class II REC prices in Connecticut. The 122 Class II sources include 95 hydropower facilities, 17 resource recovery facilities, and 7 biomass plants. In 2010 70% of the Class II requirement was met with RECs from resource recovery facilities, 16% from biomass, and 6% from hydro that does not qualify for Class I.

**Figure 18: Connecticut's Class II Resource Mix**



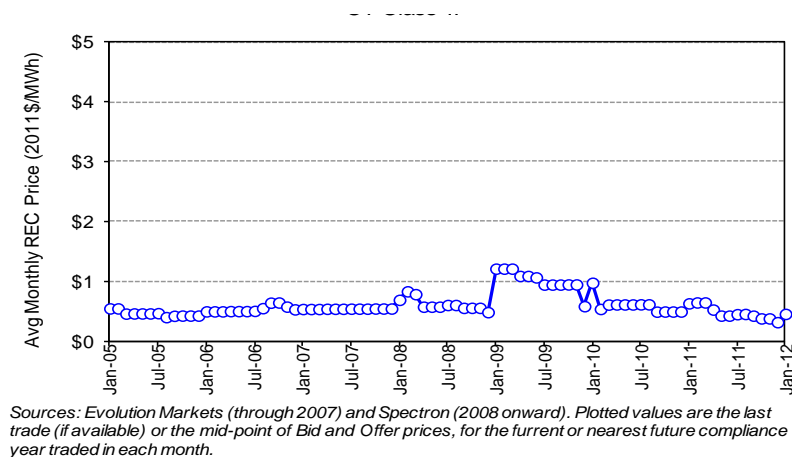
As of 2010—the latest compliance period for the RPS—approximately 47 % of RECs used in compliance for Class II were produced from generators located in Connecticut.

**Figure 19: Location of Resources Filling Connecticut's Class II Requirement**

The current supply of Class II resources significantly exceeds the existing RPS requirements. Given the state's electric demand in 2012, the Class II RPS requirement could be satisfied by 900,000 RECs. If it is assumed that the average capacity for Class II generators is 80%, the 670 MW of current Class II resources would equate to 4.7 million Connecticut Class II eligible RECs.<sup>41</sup> This surplus has driven down prices of Class II RECs to less than \$5/MWh. DEEP estimates the cost of Class II RECs to be approximately \$4.5 million in 2012.<sup>42</sup> These costs should remain about the same through 2020 unless some of the existing facilities retire or there are changes to the Class II eligibility requirements, thereby reducing the supply of Class II resources.

<sup>41</sup> IRP Appendix D-19

<sup>42</sup> IRP p. 22-23

**Figure 20: Connecticut Class II REC Prices<sup>43</sup>**

In Connecticut, resource recovery facilities comprise the largest source of Class II generation. In 2013 there are eight Class II resource recovery facilities in the state, totaling 223 MW.<sup>44</sup> In addition, Connecticut has 15 Class II hydro generation facilities totaling 16.6 MWs. Although the generation from these sources may qualify for RECs in other New England states, this capacity has created an oversupply in Connecticut Class II-eligible RECs. Continued low prices for Class II RECs may generate insufficient revenues for in-state resource recovery facilities to remain financially viable.<sup>45</sup>

Connecticut's resource recovery facilities and some of the small hydro facilities began operation in the late 1980's and early 1990's. During that period many of the Class II facilities entered into long-term power purchase agreements (PPAs) to sell their power to CL&P and UI, with contract terms ranging from twenty to thirty years. Resource recovery facilities typically contracted for 20 year terms, while the hydro facilities generally negotiated 30 year contracts.

There are currently four resource recovery facilities and eight hydro facilities located in Connecticut under long term PPAs with CL&P, located in Connecticut—totaling approximately 52.6 MW. The cost of power from resource recovery projects varies significantly between projects. Resource recovery facilities under long term PPAs will be paid between 8.3 cents/kWh and 25.0 cents/kWh in 2013-. REC revenues have not been critical to the financial viability of

<sup>43</sup> SEA RPS Training Slide deck

<sup>44</sup> DEEP RPS Database

<sup>45</sup> Currently, Class II RECs trade in the \$0.50/MWh range.

existing Class II resources as long as they are under long term contracts. However, when those contracts expire, these Class II resources may face serious financial challenges.

Several long-term contracts have already expired and others will end in the next few years. The Connecticut Resource Recovery Authority's (CRRA) 67 MW Mid-Connecticut project PPA ended in 2012. Bristol's (13.2 MW) PPA will end in 2014 and the contract with CRRA Preston (13.85 MW) will end in 2017.

Due to the combination of low Class II REC prices and low energy and capacity prices, most of these facilities will likely experience a significant revenue decline at the termination of their PPAs. Some of these resource recovery facilities claim that reduced revenues, unsold RECs, and increased costs have created financial hardship, which could threaten the continued operation of their facilities. These resource recovery facilities may attempt to compensate for revenue shortfalls by increasing disposal prices (tipping fees). Substantial increases in tipping fees, however, may be difficult to pass on to taxpayers given the financial difficulties facing many municipalities.

DEEP has not undertaken an analysis of the waste disposal needs and options in Connecticut as part of this study, but has worked with the Governor's Recycling Task Force and with other stakeholders to develop an approach to managing materials that is economically viable and advances the state's economic and environmental goals. A better understanding of this area is required to determine to what extent, if any, is required to support Connecticut's trash to energy facilities. If it is determined that more REC support is part of the solution, there are two approaches that could be taken to increase revenues to Class II resources. One approach is to raise the Class II requirement to a point where supply and demand are more balanced, thereby increasing the price of Class II RECs. Another approach is to again offer PPAs to resource recovery facilities. Additional recommendations for consideration are part of the Department's waste transformation initiative.

The impact of increasing the Class II is indeterminate since a rise in Class II REC prices could determine their economic viability. Higher REC prices and a larger Class II requirement would raise electric rates for Connecticut ratepayers with a large share of that money going to out-of-state Class II facilities. DEEP believes that PPAs offer a more targeted approach that would better ensure the continued operation of Connecticut resource recovery facilities at a lower cost to ratepayers than increasing the Class II requirements.

## CLASS III RESOURCES

Connecticut's Class III market is comprised of electric savings from in-state conservation and load management programs and energy produced by in-state combined heat and power facilities. The Class III requirement started at 1% in 2007, and increased by 1% each year until reaching 4% in 2010, at which point it remains constant through 2020. Class III RECs have a statutory price floor of 1 cent/kWh and a ceiling of 3.1 cents/kWh that was approved in a PURA decision.<sup>46</sup> DEEP estimates that it cost approximately \$12.8 million to meet the Class III RPS requirement in 2012. This cost is expected to remain constant through 2020 if current eligibility criteria are not altered.<sup>47</sup> In 2010 approximately 52% of the RECs sold to meet the Class III requirement were attributable to efficiency, while 48% were RECs from combined heat and power facilities (Figure 21).

**Figure 21: Connecticut's Class III Resource Mix**

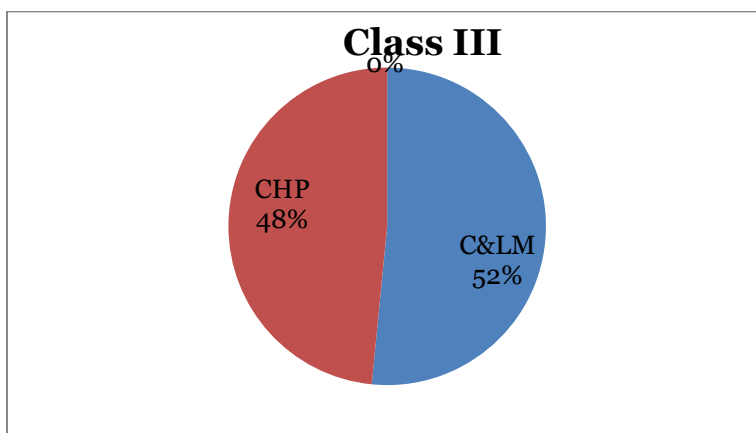


Table 14 below shows the Class III requirements and the qualifying Class III RECs between 2007 and 2010. As seen in Table 14, the current supply of Class III resources is significantly greater than the existing requirements.

**Table 14: Summary of Historical Class III Requirement and Qualifying Resource Output<sup>48</sup>**

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<sup>46</sup> DEEP RPS Data Base

<sup>47</sup> IRP p. 18-19

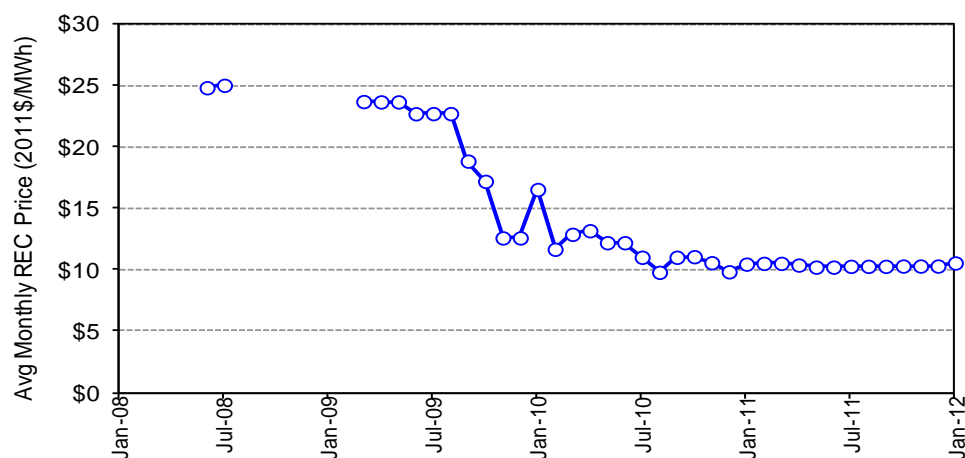
<sup>48</sup> IRP p. 18-19

Year	Class III Supply			Class III Demand
	CHP (MWh)	C&LM (MWh)	TOTAL (MWh)	
2007	0	437,854	437,854	338,736
2008	124,331	783,560	907,891	656,600
2009	528,219	1,002,482	1,530,701	951,790
2010	645,978	1,236,626	1,882,604	1,280,838

Source: Class III supply as reported in NEPOOL Generation Information System (GIS). Class III demand calculated based on existing RPS targets increasing from 1% in 2007 to 4% by 2010.

This imbalance has resulted in many Class III RECs selling at the price floor of \$10/MWh and many not selling at all. Going forward, DEEP expects the price of Class III RECs to remain at the price floor as the oversupply worsens. Utility conservation programs will generate more Class III RECs each year, keeping REC prices at the floor level and making them increasingly unmarketable.

**Figure 22: Connecticut Class III REC Prices<sup>49</sup>**



Sources: Evolution Markets (through 2007) and Spectron (2008 onward). Plotted values are the last trade (if available) or the mid-point of Bid and Offer prices, for the current or nearest future compliance year traded in each month.

Oversupply in the Class III markets has resulted largely from continued growth in utility energy efficiency programs and has impacted third-party conservation efforts. Currently there are no third party conservation providers selling class III RECs. At the floor price there is little hope for third-party conservation providers to secure substantial enough REC revenues to make such

<sup>49</sup> SEA analysis, "Renewable Energy 101 Training" slide deck



projects viable without additional ratepayer funding. Sales of Class III RECs provide an estimated \$4.5 million in supplemental revenue for utility conservation programs. This additional funding, while helpful, is not essential to the utilities' conservation efforts since they can recover their costs through electric rates.

Low REC prices have also impacted CHP units. Prices at the floor level provide little support for existing CHP units and do not encourage new development. The Class III CHP Organization (C3CO) is a coalition working on behalf of Connecticut hospitals, municipalities, businesses, and CHP developers that have invested in or plan to invest in CHP generation that meets the Class III criteria. C3CO submitted comments in the 2012 IRP and Comprehensive Energy Strategy proceedings discussing the problems of oversupply and low REC prices in the Class III market. C3CO recommends that distributed resources that meet certain environmental standards, including Class III CHP resources, and are located in the state as a component of micro grids, be used to offset a portion of the Class I requirement.<sup>50</sup> In the alternative, C3CO suggests creating a new Class IV that would be comprised entirely of conservation and load management projects, thereby removing such resources from the Class III market.<sup>51</sup>

DEEP believes that the best way to improve the Class III market would be to discontinue eligibility for conservation programs administered by the utility companies that receive funding through electric rates. If RECs from utility conservation programs were removed from the Class III market the oversupply situation would reverse and there would be an under-supply of Class III RECs. This would drive the price to the current cap of 3.1 cents per kWh. This change in the supply/demand balance may take several years if excess REC's generated by utility conservation programs that have been banked continue to be sold into the market after the eligibility requirements is changed. The higher REC prices would increase revenues for existing CHP projects and provide a greater incentive for new CHP and third party conservation development. DEEP estimates that this would increase costs from approximately \$12.8 million annually to \$20.0 million annually, as more CHP and conservation is developed. The total maximum cost of Class III would be approximately \$40 million, if the entire 3% requirement was met at the ceiling price of 3.1 cents per kWh. An important distinction of Class III is that all the conservation and CHP projects must be located in Connecticut. Therefore any increase in

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<sup>50</sup> Comments of C3CO, DEEP Comprehensive Energy Strategy proceeding, April 24, 2012.

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funding from higher Class III REC prices will go to help in-state customers and businesses reduce their electric costs and provide local economic benefits.

DEEP monitors all of the RPS markets. If third party conservation and CHP grows to a point where the existing 3% requirement is projected to be filled, DEEP would consider whether the requirement should be increased and present its recommendation to the General Assembly. DEEP believes that the eligibility for Class III should be modified to only allow conservation and load management and demand response from third party providers or utility companies that do not receive ratepayer support through electric rates other than Class III REC revenues. The Class III price cap was originally set by PURA years ago based on the average cost of the utility conservation programs at that time. The level and rationale for the cap should be reexamined periodically and adjusted if necessary.

## CONCLUSIONS AND RECOMMENDATIONS

This study presents a new renewable strategy, in line with Governor Malloy's goal of providing cheaper, cleaner, and more reliable electricity to the citizens and businesses of Connecticut. This study reveals many of the challenges Connecticut faces in achieving its RPS objectives in a cost-effective way. Connecticut's Class I RPS is disproportionately filled by out-of-state legacy biomass and landfill gas projects. Meanwhile, the current Class II and Class III markets are oversupplied resulting in low REC prices that do little to support existing resources or encourage new development. A new balance should be struck that will ensure that clean renewable resources supply an increasing share of Connecticut's electricity at an affordable price.

Based on detailed analysis and the review of comments submitted as part of the public process, DEEP has concluded that the appropriate course of action is to retain the current RPS targets of 20% by 2020, begin a gradual phase down of REC credit for biomass facilities, and to implement a renewable and low carbon, large-scale hydro procurement strategy to manage a diverse portfolio of renewable and low carbon resources that further our goals of cheaper, cleaner and more reliable energy. As part of DEEP's procurement authority this study recommends the implementation of flexibility mechanisms to enable DEEP to adjust the size of the procurement based on a determination by DEEP of the adequacy, or the potential adequacy, of renewable energy supplies to meet the increase in the percentage of the RPS compliance target. Other states such as Rhode Island and New Hampshire have implemented similar approaches.

Through carefully timed amendments to the RPS, Connecticut can shift its Class I structure strategically, to promote newer and cleaner renewable projects, and move away from reliance on biomass or landfill gas projects. At the same time, costs can be contained to protect the interests of electric ratepayers through modifications to the RPS that would allow a portion of the Class I requirements to be met with large-scale hydropower under specific conditions. The recommendations outlined below will help to diversify the mix of clean renewable resources (increasing reliability and providing a hedge against rising fossil fuel prices); provide meaningful incentives to project developers to shift support from less-clean, legacy, out-of-state renewables to new and very clean in-state and regional renewables; and reduce criteria air pollutant and greenhouse gas emissions—all at a lower cost to our citizens and businesses.

Specifically, this study recommends:

- **Continue the state's existing commitment to clean energy incentive programs to maximize deployment of cost-effective in-state renewable power.** As of 2011, Connecticut produced only about 5% (66 MW) of New England's renewable capacity, while accounting for more than a third of the Class I RPS demand in the region. As a result of renewable energy programs launched by the Malloy Administration under Public Act 11-80—including residential solar incentive programs administered by Connecticut's innovative "Green Bank" and the Low Emissions and Zero Emissions Renewable Energy Credit (LREC/ZREC) programs—Connecticut has increased its deployment of in-state Class I resources ten-fold since 2010, and is on track to deploy 55 MW of new Class I-eligible electricity in 2013. By 2020, it is estimated that 5% of the state's total electricity demand (and 25% of the state's Class I target) will be supplied by in-state renewables. An additional measure that could help to mitigate the impact of RPS compliance costs on customers' bills would be to utilize any alternative compliance payments as a refund to electric customers to offset the costs of in-state renewable programs such as LREC/ZREC.
- **Support a gradual transition away from subsidies for biomass plants and landfill gas facilities that do not provide optimal economic or environmental benefits.** This study recommends a gradual phase-down of the disproportionate share of Connecticut's RPS that is met by biomass and landfill gas facilities, many of which have been in existence since before the State's RPS was established. By gradually reducing the value of renewable energy credits awarded to those sources, the State can replace many of these resources with new, cleaner resources such as wind power, solar arrays, or other zero-emissions renewables. The study also recommends that the State be authorized to enter into power purchase agreements with some of these facilities if it determines that retaining them provides economic benefits to the state, is in the interest of ratepayers and furthers the goals of the Comprehensive Energy Strategy and the Global Warming Solutions Act (ie., because the withdrawal of RPS support for a biomass or landfill gas facility would otherwise cause it to exit the market, and be replaced by fossil fuel generation).
- **Expand support for small hydropower.** Under current RPS rules, to qualify for Class I, a hydropower project must be built after 2003, be run-of-river, and have a generating capacity of less than 5 MW. This study recommends expanding the definition for Class I hydro eligibility from 5 MW to 30 MW to broaden support for hydropower

and better align rules with neighboring states, at the same time to ensure proper environmental safeguards are in place the definitions should clarify that an eligible small hydropower facility must not be based on a new dam or a dam identified as a candidate for removal, and must meet state and federal requirements and any applicable site-specific standards for water quality and fish passage.

- **Expand support for anaerobic digesters and biologically-derived methane.** Connecticut currently allows “methane from landfill gas” as a Class I resource, as do each of the other New England states. This study recommends that the Class I definition be modified to allow all methane/biogas that is biologically-derived—i.e., produced from sources such as yard and plant matter, food waste, animal waste and sewage sludge—and produced by new technologies such as anaerobic digesters to qualify as a Class I source.
- **Authorize the state to procure low-cost Class I renewable supply through long-term contracts.** This study recommends that DEEP should be given authority to participate in regional renewable procurement for Class I resources. This study proposes several rounds of clean energy procurement in the next year or two. The resources would ideally be procured in conjunction with other New England states and would be used to help meet the existing Class I requirements.
- **Authorize the State to contract for low-cost, low-carbon, large-scale hydropower to complement in-state and regional renewable energy procurements, provide greater diversity in energy supply, and help achieve the requirements of Connecticut's Global Warming Solutions Act.** Large-scale hydropower resources, such as those found in Quebec and the Eastern Canadian provinces, offer a source of low-carbon power at very competitive costs that has the potential to increase the diversity and reliability of electricity generation in a state that is dominated by nuclear and natural gas generation, and to provide a cleaner alternative to natural gas that can “balance” intermittent resources like solar and wind. This study recommends authorizing the State—either on its own, or in coordination with other New England states—to solicit proposals for long-term contracts for Class I resources or large scale hydropower for up to five percent of the state's load. Under the proposal in the final version of this study, any contracted large-scale hydro would not automatically count toward meeting the RPS compliance obligation, but would be counted toward the greenhouse gas reduction requirements of the state's Global Warming Solutions Act. In

the event that there is a verified shortfall in Class I supply, this study proposes a mechanism whereby large-scale hydro could be allowed to count towards up to one-percent of the RPS target, and no more than five percent by 2020, without receiving any RECs. Such a mechanism could help to reduce RPS compliance costs for Connecticut ratepayers. This proposal will preserve the opportunity for Class I projects to meet the current RPS standards, while at the same time creating a hedge to protect ratepayers from high RPS compliance costs if eligible Class I projects cannot be developed in time.

- **Discontinue Class III incentives for efficiency programs that are already ratepayer funded.** There is a significant oversupply of Class III resources. Since the programs provided through the State's Conservation and Load Management Plan are already supported by ratepayers, this study recommends that any efficiency programs supported by ratepayer funding through the Energy Efficiency Fund not be eligible to qualify for additional ratepayer support through the Class III market. Eliminating these resources would open up the market to more combined heat and power (CHP) projects and third party efficiency providers not supported by the Conservation and Load Management programs.

The recommendations described above will enable Connecticut to achieve a more balanced and flexible approach to renewable power development, continue support for in-state renewable power projects that benefit the local economy, work with neighboring states to procure the cheapest possible regional renewable resources in the near term, and maintain the flexibility to purchase large amounts of low-cost, large-scale hydropower and apply it towards the RPS only in the event that cost-competitive regional Class I resources are in short supply. By taking structured steps to procure renewable electricity, Connecticut can also help to drive smart investments in transmission that will provide access to resources that will reduce greenhouse gas emissions, improve the flexibility and reliability of the electricity grid, achieve rate suppression in Southern New England, provide a hedge against spikes in natural gas prices, increase the diversity of Connecticut's electricity supply, and potentially secure greater supplies of clean, low-cost power during times of peak demand. Such a new RPS structure would reinforce the policy direction of Connecticut's new Comprehensive Energy Strategy, and advance Governor Malloy's commitment to cheaper, cleaner, and more reliable electricity.